GE BWR/4 Advanced Course
R-504B

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Prior to the discussion of transient analysis it is essential to review some of the control systems covered in the Systems Course. The purpose of this section is cover the electro hydraulic control (EHC) system's response to various failures. Using the attached EHC system figures, discuss the plant response to each of the following events:

1. **Failure of the turbine load set causing it to run back to zero (0).**
2. **The cooldown bypass jack signal is increased to 3%.**
3. **Failure of the in service pressure regulator to maximum signal out.**
4. **Failure of the in service pressure regulator to minimum signal out.**

The discussion of the plant events, listed above, should include the transient and steady state conditions.

The initial plant conditions are indicated below:

Reactor Power	100%
Total Core Flow	100%
Reactor Pressure	1005 psig
Turbine Load Selector	100%
Turbine Speed Set	Synchronous Speed Selected
Pressure Set	920 psig
Max. Combined Flow set	105%
Load Limit Set	100%
Bypass Capacity	25%

Introduction

Inform the class they have approximately 30 minutes to work the EHC problems and **NOT** to compare answers with their neighbors. With the EHC transparency have the class fill in all the given values.

Problem # 1

Turbine Load set runs back to Zero

1. As the load set value decreases below 100% , the CV demand signal decreases accordingly. AS the control valves demand signal decreases the bypass valve summer compares the signal decrease to the pressure control signal and passes the difference which opens the BPVs.

2. This process continues until the bypass valves reach their allowed maximum opening of 25%, which corresponds to a 75% CV signal. When the signal is further reduced, the CVs continue to close which creates an energy mismatch between the reactor and its heat sink, requiring reactor pressure to increase.

3. When pressure increases to the scram value or APRM high flux is received, the reactor will scram.

4. In either case with the reactor scrammed, heat output decreases to decay heat values which is below the capacity of the BPVs, thus requiring them to throttle back and control pressure.

Problem # 2

The cooldown bypass jack signal is increased to 3%.

1. When the cooldown bypass jack increase push button in depressed, its output ramps from zero to 3% as long as the pushbutton is depressed.

2. The jack signals compared to the summer signal at the HVG allowing the jack signal to pass because its the largest signal.

3. The output of the HVG is compared to the maximum combined flow /control valve demand summer at the LVG. With the BPV demand signal being less than the summer signal the BPVs open to 3%.

4. As the BPVs throttle open to 3%, turbine throttle pressure begins to decrease. The decrease in throttle pressure is compared to the pressure setpoint signal which causes the CVs to throttle close accordingly.

5. Since steam flow is essentially unchanged the steam line d/p remains at 55 psid which means that reactor pressure decreases as throttle pressure decreases.

Reactor power may increase a little due to the decrease in feedwater heating.

6. (30 psid)(97%) = 29.1 psid. Throttle pressure will stop decreasing at a value of 949.1 psi., for a total reduction of .9 psi. Reactor pressure then must be 1004.1 psig.

Problem # 3

EHC Fails High

1. With the normal settings of the EHC system (MCF=105%, load limit=100%, load limit=100% and the pressure set point=~~950~~ 920 psig), combined with the pressure regulator failing to maximum the BPVs will open to pass 5% steam flow in addition to the CVs passing 100%. The BPVs ar limited to only 5% by the maximum combined flow limiter setting.

2. The imbalance between heat production and removal is observed with a decrease in reactor pressure. This decrease in reactor pressure creates more voids in the core region, thus a power decrease.

3. When reactor pressure decreases to approximately 880psig the MSIVs close on low steam line pressure which is lower than reactor pressure due to the steam line losses. With the MSIVs closed reactor pressure increases to SRV opening set point.

4. Pressure is maintained with the SRV cycling until reactor water level reaches level 2. At this point the water introduction from HPCI and RCIC, in addition to the steam used by their respective turbines, lowers reactor pressure and increases reactor water level.

Problem # 4

EHC Fails Low

1. With the normal settings of the EHC system (MCF=105%, load limit=100%, load limit=100%, pressure set point = 920psig, controlling regulator input to HVG 30 and standby at 27 psi), combined with the pressure regulator failing low, the backup pressure regulator becomes the controlling regulator via the HVG.

2. The initial closure of the turbine, causes reactor pressure to increase.

3. The increase in reactor pressure collapses voids in the core causing reactor power to increase. Reactor power increase is terminated when the backup regulator gains control of reactor pressure and reopens the turbine control valves to the 100% demand signal.

4. With 100% steam production, and usage, reactor power returns to its original value after the minor disturbance. Reactor pressure stabilizes at 1008 psig with turbine throtttle pressure at 953 psig.

2.2 CORE HEAT BALANCE

Special Instructions:

1. **Calculators available**

2. **Training Aids**
   a. **Table 2.2-1**
   b. **Figure 2.2-1and 2.2-2**
   c. **Feedwater CTP Normogram**
   d. **Heat balance - Viewgraph**

References

1. BFNP training instructions TI 1.1
2. Insided NRC - November 20, 00
3. Nucleonics Week - August 26, 99
4. Event reports
5. Caldon Letter - February 15,00

Learning Objectives

Viewgraph

Learning Objectives

1. **List three purposes of a core heat balance.**
2. **List the three methods that can be used to obtain core thermal power.**
3. **List the parameters used in a heat balance calculation and indicate the most critical parameter.**

2.2.1 Introduction

The thermal power of the reactor core is determined by a heat balance on the nuclear boiler using operating data. Under steady state conditions, the nuclear boiler heat output is obtained as the difference between the total heat removed from the boiler system minus the total heat added in the flow streams returning to the boiler.

Objective #1

A core heat balance in the power range, greater than or equal to 10% power, is made to ensure that the core is operated at all times within licensed thermal limitations and/or fuel warranty requirements. The results of heat balance calculations also provide input to additional core calculations (i.e., CPR & APLHGR).

Objective #2

2.2.2 Methods of Calculation

Four methods of calculating the energy output of the core by heat balance are used:

- Short Form Method - used when a fast estimate is needed and a high degree of accuracy is not essential.
- Long Form Method - considers all heat losses and additions.
- Process Computer - Normal calculational method.
- Off-line Computer

Either the manual long form method or the off-line computer method is required when the process computer is unavailable. This instruction covers the manual method long form and is addressed in NRC "Inspection and Enforcement Manual" chapter (IMC), 61706B.

Objective #3

The core thermal power is obtained by writing an energy balance on a system composed of the reactor vessel, recirculation loop piping, and cleanup demineralizer piping. Flows entering the system are the reactor feedwater flow and the control rod drive system flow. The only flow assumed to be leaving the system is the primary steam flow. Non-flow power losses are the radioactive power loss and the net power transferred across the boundary of the cleanup demineralizer loop.

Have the students come up with the basic heat balance equations.

With the aid of the heat balance color viewgraph discuss heat inputs vs outputs.

Following this discussion, or in addition to it, have the students provide the source of the data (i.e. feedwater flow, CRD flow, Feedwater temperature, etc..)

Figure 2.2-1 is a schematic diagram of the energy inputs and outputs to be evaluated. Mathematically, the heat balance equation is derived as follows:

The heat outputs from the system include:

Main Steam = $m_{MS} \times h_{MS}$ (equation A)

Cleanup System = $m_{CU} \times (h_{in} - h_{out})$ (equation B)

Where: $m_{CU} = m_{CU(A)} + m_{CU(B)}$

Fixed Losses = Q_{FL} (equation C)

The heat inputs to the system include:

Feedwater = $m_{FW} \times h_{FW}$ (equation D)

CRD Hydraulic = $m_{RD} \times h_{RD}$ (equation E)

Recirculation Pumps = Q_P (equation F)

Core Power = Q_C (equation G)

Since the measurement of main steam flow is normally much less accurate than the measurement of feedwater flow, and since this is a closed system, let:

$m_{MS} = m_{FW} + m_{RD}$ (equation H)

Substituting Equation H into Equation A:

Main Steam = $h_{MS} \times (m_{FW} + m_{RD})$ (equation I)

The total heat outputs are therefore:

Outputs = $K[h_{MS}(m_{FW} + m_{RD}) + m_{CU}(h_{in} - h_{out})] + Q_{FL}$ (equation J)

The total heat inputs are therefore:

Heat Inputs = $K[(m_{FW} \times h_{FW}) + (m_{RD} \times h_{RD})] + Q_P + Q_C$ (equation K)

Since the heat inputs must equal the heat outputs, equation J is set to equation K:

$K[(m_{FW} \times h_{FW}) + (m_{RD} \times h_{RD})] + Q_P + Q_C = K[h_{MS}(m_{FW} + m_{RD}) + m_{CU}(h_{in} - h_{out})] + Q_{FL}$ (equation L)

Solving Equation L for Core Power:

Q_C=K [h_{MS} (m_{FW} + m_{RD}) + m_{CU} (h_{in} - h_{out}) - $m_{FW}h_{FW}$ - $m_{RD}h_{RD}$]+ Q_{FL} - Q_P (equation M)

Combining all terms and rearranging yields the equation representing total Core Thermal Power:

Q = K[m_{FW} (h_{MS} - h_{FW}) + m_{RD} (h_{MS} - h_{RD}) + m_{CU} (h_{in} - h_{out})] + Q_{FL} - Q_P (equation N)

Where:

Qc = Core thermal power (MWt)

K = 2.93 x 10-7 MWt-hr/BTU

m_{FW} = Feedwater Flow (lbs/hr)

m_{RD} = Control rod drive flow (lbs/hr)

m_{CU} = Clean-up System flow (lbs/hr)

h_{MS} = Enthalpy of main steam (BTUlb)

h_{FW} = Enthalpy of feedwater (BTU/lb)

h_{RD} = Enthalpy of control rod drive flow (BTU/lb)

h_{in} = Enthalpy of inlet flow to cleanup system (BTU/lb)

h_{out} = Enthalpy of return flow from cleanup system (BTU/lb)

Q_{FL} = Fixed Losses (MW) = 0.6 MW

Q_P = Recirculation pump work (7.6 MW)

For the case in which an estimate of this value is desired rapidly, the curves of Figure 2.2-2 may be used. These curves are based upon a simplification of equation N of the form:

Qc = K [m_{FW} (h_{MS} - h_{FW})] + Constant (equation 0)

The above constant is composed of all the small heat input and output terms that complete the thermal energy balance.

It is defined as:

$$\text{Constant} = K\,[\,\dot{m}_{RD}\,(h_{MS} - h_{RD}) + m_{CU}\,(h_{in} - h_{out}) + Q_{PL} - Q_{L}\quad \text{(equation P)}$$

Heat Balance Calculation Problem

Prior to having the students work the heat balance problem discussion the Assumption.

2.2.3 Heat Balance Calculation Problem

Table 2.2-1 includes a practice problem for performing a core heat balance. Using the values on form TI 1.1 of the table and the attached steam tables, calculate the core thermal power.

2.2.3.1 Assumptions

Core thermal power is equal to or greater than 329 MWt (10% power)

Reactor Water Cleanup system flow is directed back to the reactor.

Exponents - powers of 10 are compensated for in the formula derivations or are specifically indicated.

Assume atmospheric pressure is 15 psia.

Check results against the nomograph.

Following the calculation of thermal power discuss the NRC letter from Jordon toe branch chiefs.

2.2.4 Licensed Power Level

The following is the text of an internal NRC letter from Mr. E. L. Jordon (Director, Office of I&E, August 22,1980) to the Branch Chiefs of Reactor Operations in each Region. The letter provides guidance to inspectors for determining licensee compliance with Licensed Power limits. This guidance is still in effect today. A copy of the letter can be found in the Document Control System:

Dating back to at least 1974, there have been many lengthy "discussions" regarding the exact meaning of "full, steady-state licensed power level" (and similarly worded power limits). We do not believe the real safety benefits that might be derived from an NRC-wide agreement would be worth the further expenditure of manpower in meetings, etc. that would be required to achieve a consensus.

We do realize that some common uniform basis for enforcing maximum licensed power is needed by I&E inspectors. Therefore, until and unless an NRC-wide position is put forward and agreed upon (and as stated, I&E does not propose to initiate proceedings to that end), I&E will use the following guidance:

The average power level over any eight hour shift should not exceed the "full steady-state licensed power level" (and similarly worded terms). The exact eight hour periods defined as "shifts" are up to the plant, but should not be varied from day to day (the easiest definition is a normal shift manned by a particular "crew"). **It is permissible to briefly exceed the "full, steady-state licensed power level" by as much as 2% for periods as long as 15 minutes. In no case should 102% power be exceeded,** buy lesser power "excursions" for longer periods should be allowed, with the above as guidance (i.e., 1% excess for 30 minutes, 1/2% for one hour, etc., should be allowed). There are no limits on the number of times these "excursions" may occur, or the time interval that must separate such "excursions", except note that the above requirement regarding the eight hour average power will prevent abuse of this allowance. The above is considered to be within the licensing basis and, therefore, acceptable to us, and it is also fair to the utilities and their ratepayers.

2.2.5 100% Power

Objective #3

Core thermal power for nuclear power plants is controlled on the basis of a licensed thermal power rating. Nuclear instruments and plant calorimetrics are used to monitor reactor power. **The accuracy of the calorimetric power determination (heat balance)is sensitive to several measurements, but is most affected by feedwater flow measurement accuracy.** Thus, an accurate determination of core thermal power hinges on the accurate knowledge of feedwater flow.

non-conservative errors in feedwater flow measurement

Two non-conservative errors in feedwater flow measurement led to power in excess of the licensed thermal power limit at FitzPatrick. The feedwater flow transmitters were replaced on October 3, 1988, but were not calibrated properly. The calibration was completed on November 14, 1989. When more accurate transmitters were placed in service on January 29, 1990, the power level was found to exceed the licensed limit. Power was immediately reduced.

Flow element vendor input errors have since been identified and corrected.

Operation in excess of the thermal power limit occurred at Oyster Creek on May 11, 1990 and again on August 1, 1990. The first event occurred because of a miscalculation in the plant heat balance equation. The second event, August 1, 1990, was a result of feedwater flow calibration calculation which was approximately 2% in the nonconservative direction.

Operation in excess of the thermal power limit occurred at Cooper Nuclear Station from 1980 to April 1994, at those times when the reactor was operated at full power. The actual reactor power was approximately 2400 MWt while the calculated power level was 2381 MWt. This was attributed to the licensee not compensating for an error in the calibration of the pressure transmitters used for feedwater flowrate determination.

The common link in all of these cases is that there was no indication of a problem until an independent means of measurement or calculation was employed. The existing feedwater flow measurement instrumentation, for most BWR plants, consists of a differential pressure transmitter providing an output proportional to the differential pressure across the flow nozzle. Resistance thermometers (or thermocouples) measure the feedwater temperature. Typically, these outputs are supplied to the plant computer where the density and enthalpy are calculated with the aid of synthesized ASME steam tables. Thermal power is then calculated by the plant computer.

Operation experiences in the United States, Japan, and Germany has shown that venturi flow measurement accuracy is susceptible to degradation. The principle source of degradation is fouling with corrosion deposits, which adhere preferentially to the nozzle throats of the venturi tubes. The corrosion deposit fouling causes an increase in the differential pressure measured for a given volumetric flow and results in erroneously high feedwater flow readings. When the overestimates of feedwater flow are used to calibrate the nuclear instruments, these calibrations result in operating with the actual core thermal power below the intended level. Various studies have shown that fouling recurs during each operating cycle and can contribute up to 2 to 3 percent reduction in thermal power, $$$$.

In the August 26, 1999 issue of Nucleonics Week an article stated "GE PROPOSES BWR UPRATES OF 1% BASED ON GENERIC APPROACH". The article stated that in mid August . General Electric (GE) submitted a proposal to the NRC that would allow BWR owners to proceed with 1 % uprates by reducing conservatism in calculating reactor power.

GE wants to take advantage of the awaited NRC approval of a similar generic uprate for PWRs based on uncertainty reductions stemming from use of a new feedwater measurement technology.

The NRC approved an exemption to allow Texas Utilities to reduce the error assumption calculated into its heat balance from 2% to 1% at its two Comanche Peak PWRs, and the utility followed with a request for a power uprate.

The Caldon **Leading Edge Flow Meter (LEFM)** is currently the only such instrument approved by the NRC but ABB Combustion Engineering may soon introduce the Crossflow, its own feedwater flow measuring device and is closely following GE's generic proposal.

Hope Creek has installed the Westinghouse Cross Flow Feedwater Flow measurement device and has increased there power rating 1.4%
6/27/01

On May 3, 2000, the NRC approved a rule change amending 10CFR50 Appendix K to permit power increases based on improvements in accuracy of the instrumentation used to measure thermal power. These power increases, referred to as "Appendix K Uprates" are relatively small increases on the 1% to 1.7% range, depending on the demonstrated instrument accuracy.

It is anticipated that licensees will make use of the new measurement instruments such as the LEFM mass flow and temperature measurements by directly substituting the new information in the plant computer. The plant computer would then calculate enthalpy and thermal power as it does now. In order to maintain control of thermal power at 100 percent power, a real-time display of thermal power, as calculated using the new technology, will be available in the main

control room for the reactor operator's use. The operators would then use the new display to maintain reactor power at or below the licensed thermal power limit. A validity indication will also be present to alert the operators of the condition of the new instruments.

Described below are **three ultrasonic technologies used in the measurement of volumetric flow in a pipe:**

- **Chordal Transit Time system (LEFM)** consisting of arrays of ultrasonic transducers housed in fixtures in a pipe so as to form parallel, precisely defined acoustic paths. The times of flight of pulses of ultrasonic energy traveling along these paths are measured to determine the volumetric flow and the velocity of sound of the flowing fluid. A numerical integration method is used to determine the volumetric flow rate directly from the meter's four path velocities without the need for a pipe area measurement.

- **Externally Mounted Transit Time systems** consisting of ultrasonic transducers mounted on the exterior of the pipe so as to form one or more diagonal and diametral acoustic paths. The times of flight of pulses traveling between pairs of transducers are measured to determine the axial fluid velocity projected onto the acoustic path (In some designs, the fluid sound velocity is also measured.). With knowledge of the shape of the axial velocity profile, the mean fluid velocity can be inferred from the axial fluid velocity measurement. The volumetric flow is then calculated as the product of the mean axial velocity and the pipe cross sectional area.

- **Cross Correlation systems(Canadian General Electric)** consisting of two pairs of ultrasonic transducers mounted so as to form two parallel diametral paths, perpendicular to the axis of the pipe, and separated by a known axial distance. One transducer in each path continuously transmits ultrasound to the opposite transducer on that path. The received signal for the upstream path is subjected to an adjustable time delay, then cross correlated with the downstream signal. A characteristic fluid velocity is calculated from the quotient of the distance between acoustic paths and the time delay at which maximum correlation is achieved. The mean axial

- velocity is inferred from this characteristic fluid velocity. The volumetric flow is then calculated as the product of the mean axial velocity and the pipe cross sectional area.

2.2.6 Summary

The thermal power of the reactor core is determined by a heat balance on the nuclear boiler using operating data. Under steady state conditions, the nuclear boiler heat output is obtained as the difference between the total heat removed from the boiler system minus the total heat added in the flow streams returning to the boiler.

A core heat balance in the power range, greater than or equal to 10% power, is made to ensure that the core is operated at all times within licensed thermal limitations and/or fuel warranty requirements. The results of heat balance calculations also provide input to additional core calculations (i.e., CPR & APLHGR).

Either the manual long form method or the off-line computer method is required when the process computer is unavailable.

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3.0 TECHNICAL SPECIFICATION ORGANIZATION

Learning Objectives :

1. State the purpose of Technical Specifications
2. State the purpose of Specification 3.0.3.

3.0.1 Introduction

The purpose of Technical Specification is to protect the health and safety of the public by imposing limits, operating conditions, and other similar requirements on the facility.

The legal requirements for plant technical specifications are found in 10 CFR 50.36 which states "The technical specifications will be derived from the analyses and evaluation included in the safety analysis report....". Paraphrasing this statement, technical specifications define the limits of plant operation to ensure that the plant is operated within those boundaries established by the Safety Analysis. For example, if the safety analysis uses a maximum reactor coolant system pressure of 1325 psig then a technical specification limit of 1325 psig will be imposed. After the plant's technical specifications have been approved by the Commission, they become part of the licensing document.

3.0.2 Derivation

The format for technical specifications evolves from 10 CFR 50.36 which lists the following categories to be included in technical specifications:

- Safety limits and limiting safety system settings,
- Limiting conditions for operation,
- Surveillance requirements,
- Design features, and
- Administrative controls.

For special items of interest, the NRC issues Regulatory Guides which describe methods acceptable to the NRC staff of implementing specific parts of regulations. One such Regulatory Guide (1.70) provides the STANDARD format and content of Safety Analysis Reports (SARs). This guide specifies seventeen chapters in the SAR, and assigns technical specifications to Chapter 16. Portions of this Regulatory Guide dealing with technical specifications are included below.

3.0.3 Format

There are three technical specification formats that are currently being used. The oldest of these formats is called "custom" technical specifications because the format that was used was decided by the utility. Attachment A illustrates a typical "custom" specification for chemistry. The specification is actually a limiting condition for operation. A limiting condition for operation is defined as a requirement that must be satisfied for the unrestricted operation of the unit. The statements that follow the limiting condition for operation (LCO) are actions that must be taken in the event that the LCO cannot be satisfied. Note that the actions of these statements require a plant shutdown if the LCO cannot reestablished. The bases for the specification follow the limiting condition for operation and its associated action statements. The surveillance, to ensure that the LCO is satisfied, is located in the right hand column across from the LCO.

In the mid seventies, the format for technical specifications was changed to a "standard" format. This format is shown in Attachment B. The standard technical specifications format starts with the LCO statement. Again, the LCO must be satisfied for unrestricted operation. The action statements, i.e., the required actions that must be taken if the condition of the LCO cannot be satisfied, are listed next. The surveillance requirements follow the action statements. Bases for a particular specification are in separate sections of the document.

The third version of technical specifications, NUREG-1433, Revision 1, was issued in April of 1995 and incorporates the cumulative changes resulting from the experience gained from license amendment applications. Many licensees have or plan to convert to these improved Standard Technical Specifications (STS) or to adopt partial improvements to existing technical specifications. NUREG-1433 was the result of extensive public technical meetings and discussions between the Nuclear Regulatory Commission staff and various nuclear power plant licensees, Nuclear Steam Supply System (NSSS) Owners Groups, specifically the GE Owners Group, NSSS vendors, and the Nuclear Energy Institute. The improved STS were developed based on the criteria in the Final Commission Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors, dated July 22, 1993. Licensees are encouraged to upgrade their technical specifications consistent with those criteria and conforming, to the extent practical and consistent with the licensing basis for the facility, to Revision 1 to the improved STS. The Commission continues to place the highest priority on requests for complete conversions to improved STS. Licensees adopting portions of the improved STS to existing technical specifications should adopt all related requirements, as applicable, to achieve a high degree of standardization and consistency.

The new improved STS consist of three volumes:

- Technical Specifications,
- Bases, and
- Technical Requirements Manual

The technical specifications volume, illustrated in Attachment C, begins with the LCO followed by the applicability, action, and surveillance sections. The actions sections are divided into three columns (condition, required action, and completion time) while the surveillance sections are divided into two sections (surveillance and frequency). This format is provided to better articulate to the operator the conditions that exist and what must be performed for that condition.

3.0.4 New Revised Standard Technical Specifications

The description that follows is based on the new revised standard technical specification format (the third format discussed above) and will be used in the Advanced Technology and Simulator Courses.

3.0.4.1 Use and Application

This section of technical specifications manual is comprised of four subsections:

- Definitions
- Logical Connectors
- Completion Times
- Frequency

Subsection 1.1 provides defined terms that appear in capitalized type and are applicable throughout technical specifications and bases.

The Logical Connectors, subsection 1.2, explains the meaning of logical connectors and provides examples to illustrate their usage.

The Completion Time, subsection 1.3, establishes the completion time and provides guidance for its use.

The Frequency, subsection 1.4, defines the proper use and application of frequency requirements.

3.0.4.2 Safety Limits

This section of the plant technical specifications establishes the requirements for the protection of the fission product barriers. These requirements are called safety limits. For BWRs, the safety limits are:

- *Thermal Power*, Low Pressure or Low Flow
- *Thermal Power*, High Pressure and High Flow
- Reactor Coolant Pressure
- Reactor Vessel Water Level

When these limits are satisfied, then the fuel cladding and reactor coolant system pressure boundaries are protected during anticipated operational occurrences.

3.0.4.3 LCOs and Surveillance Requirements

Sections 3.0/4.0 are used to establish the ground rules for the remaining portions of technical specifications. One of the most important specifications in this section is 3.0.3, the "motherhood" statement. This specification provides guidance for plant operation when the LCO and its associated action statements cannot be satisfied. For example, one of the ECCS LCOs requires two trains of low pressure systems to be operable. If one train is out of service, operation may continue for some time period. However, if both trains are out of service the actions of specification 3.0.3 must be taken. In summary, when the plant is less conservative than the least conservative technical specification action statement, go to specification 3.0.3. In addition to providing guidance for plant operation in unusual conditions, sections 3.0 also endorses ASME section XI as the testing document for power plant pumps and valves.

The remaining parts of 3/4 specifications deal with individual systems. The following is a listing of the sections or categories and their associated systems:

- 3.1 Reactivity Control Systems
- 3.2 Power Distribution Limits
- 3.3 Instrumentation
- 3.4 Reactor Coolant System
- 3.5 Emergency Core Cooling System

- 3.6 Containment Systems
- 3.7 Plant Systems
- 3.8 Electrical Power Systems
- 3.9 Refueling Operations
- 3.10 Special Operations

3.0.4.4 Design Features

Section 4.0 describes the important design features of the unit. Items such as the cyclic limits of the reactor coolant system and it associated components are listed here. In addition, the emergency plan exclusion and low population areas are shown in this section.

3.0.4.5 Administrative Controls

Administrative controls delineate the management and staff organization, review and audit groups, record and reporting requirements, and procedures required to assure safe plant operation. The administrative organization is addressed in terms of offsite management and onsite staff requirements including the minimum shift crew composition for all plant conditions. The review of safety related matters is conducted by Plant Review Board and the Safety Review Board. Although these are separate groups, they function together in the review and submittal of reports concerning safety matters.

The General Manager shall provide direct executive oversite over all aspects of the plant. The Assistant General Manager-Plant Operations shall be responsible for overall unit operation. Offsite and onsite organizations, in addition to shift manning, are established per administrative control section 6.2.

3.0.5 Bases

The bases for technical specifications requirements is found in a separate BASES manual

VIEWGRAPHS
• use of Application
• TRM specifications

3.0.6 Technical Requirements Manual

The Technical Requirements Manual (TRM) contains specifications and operational conveniences, such as lists, cross references, acceptance criteria, and drawings. TRM specifications are contained in Section 3.0 and include operational requirements, surveillance, and required actions for inoperable equipment. Instructions for the use and application of TRM specifications are included at the beginning of Section 3.0

Operational conveniences provide a ready reference to setpoints, lists, and other helpful tools described in plant procedures and programs.

Other plant documents, such as Fire Hazards Analysis, Appendix B, Core Operating Limits Report (COLR), and Offsite Dose Calculation Manual, are not considered part of the Trm, but are included with the TRM as Appendices, and either contain their own rules of usage or are covered by plant documents.

Core Operating Limits Report

Many of the limits discussed in this section must be revised for every core reload cycle. to make a change, a license amendment is required, which must be reviewed by an onsite safety review board and the NRC. This makes any change to these limits a large administrative burden.

NRC Generic Letter 88-16, "Removal of Cycle-Specific Parameter Limits for Technical Specifications," dated October 4, 1988, provided guidance for relocating certain cycle dependent core operating limits from Technical Specifications to a Core Operating Limits Report (COLR). The COLR will still be reviewed, but not as a license amendment. Typical core operating limits include the following:

- Control Rod Program Controls
- Average Planar Linear Heat Generation Rate
- Minimum Critical Power Ratio
- Linear Heat Generation Rate

In addition, an entry is added to the definitions to define COLR, and the administrative technical specifications are modified to show the COLR as part of the reporting requirements.

3.0.7 Probability Risk Assessment

Probability Risk Assessment (PRA) of a nuclear power plant provides a tool to quantitatively evaluate the risk implications of Technical Specification (TS) requirements and the risk impact of changes in these requirements. Use of a PRA to evaluate or assess TS requirements and study their modifications is called PRA-Informed TS evaluation. Such evaluations are used along with a broad spectrum of considerations which include deterministic analyses, knowledge of lessons learned from operating experiences, and engineering judgments to define or alter TS requirements. When a modification to TS is analyzed using PRA and submitted to the regulatory authority for approval, it is commonly referred to as a PRA-Based or Risk-Informed TS submittal. The review and acceptance of the requested modification in the submittal by the regulatory authority constitutes a change in the plant TS.

Assessing the risk impact of a TS change is a useful input in analyzing, reviewing, and accepting the change. Risk-Informed TS submittal evaluations have primarily focussed on limiting conditions for operations LCOs) and surveillance requirements. Specifically, PRA-Informed evaluations can be used to address:

- LCO - Identify or define the condition for which a requirement should be defined.
- LCO - Rethink allowed outage time.
- LCO - Determine the required action, i.e., the need for shutdown, additional testing or operability requirements.

PRA-Informed TS submittals primarily deal with permanent changes to TS requirements. The majority of the submittal are motivated to avoid a mode change (plant shutdown).

3.0.6 Exercise

According to technical specifications, when is a recirculation loop considered in operation?

3.1 CONTROL ROD PROBLEMS

Learning Objectives:

1. State the requirements for Technical Specifications and explain the significance of Limiting Condition for Operation as applied to control rod operablilty, control rod scram times, and Rod Worth Minimizer operability.

2. When given an initial set of operating conditions, the student will be able to use the format and content of the Technical Specifications to identify the applicable plant/or operator response.

Allow students approximately 25 minutes to determine LCO and answer lesson objectives.

Exercise

You are a resident inspector at a BWR/4 plant that has just completed a 125 day refueling outage. When you arrive at the station, the post outage plant startup is in progress. You proceed to the control room and review the shift supervisor's log. The following entries are recorded.

- Commenced a reactor startup, mode switch placed in startup/hot standby position.
- reactor critical, critical data taken
- at the point of adding heat
- Rod Worth Minimizer failure, Ops supervisor informed.
- Mode switch placed in run position.
- Plant chemist reports SLC concentration at 6.3% with a volume of 3000 gal.
- Paralleled to grid.
- Scram testing commenced.

While reading the log you hear the reactor operator inform the STA that rod 10-43 will not move.

Consult Technical Specifications, to determine control rod operability requirements, scram times requirements, and Rod Worth Minimizer requirements.

Have the students make a list some of the systems required to be operable before startup.

Systems required to be operable:
- ECCSs
- RPS
- RWM
- RMCS
- Recirulcation system
- Primary and secondary containment
- NMS

Rod Pattern Control
3.3.2.1 page 3.1-16

Bases RWM page B3.3-45

Cover bases of RWM and requirements and purpose with help of the students.

Ask the class how many rods have been withdrawn. Number is not important. However, the sequence is beyond the BW pattern is!!

The RWM was allowed to be bypassed provided startup with the RWM inoperable has not been performed in the last year AND in compliance with the BPWS. In addition, a second qualified individual must verify withdrawal of rod is correct sequence.

RWM

The purpose of the RWM is to control rod patterns during startup and shutdown, such that only specified control rod sequences and relative positions are allowed over the operating range all rods inserted to 10% RTP. The sequences effectively limit the potential amount and rate of reactivity increase during a CRDA. The RWM determines the actual sequence based position indication for each control rod. The RWM also uses feedwater flow and steam flow signals to determine when reactor power is above the preset power level at which the RWM is automatically bypassed.

The RWM enforces the banked position withdrawal sequences (BPWS) to ensure that the initial conditions of the CRDA are not violated. The BPWS requires that control rods be moved in groups, with all control rods assigned to a specific group to be within specified banked positions.

Since the RWM is a system designed to act as a backup to operator control of the rod sequences, only one channel of the RWM is available and required to be operable. Special circumstances provided for in the required Action of LCO 3.1.1 and 3.1.6 may necessitate bypassing the RWM to allow continued operation with inoperble control rods, or to allow correction of a control rod pattern not in compliance with the BPWS.

Compliance with the BPWS, and therfore operability of the RWM, is required in Modes 1 and 2 when thermal power is <10% RTP. When RTP is >10%, there is no possible control rod configeration that results in a control rod worth that could exceed 280 cal/gm fuel damage limit. The NRC requires the RWM to be highly reliable to minimize the need to depend on a second qualified individual. To accomplish this, RWM must be operable during the first 12 rod withdrawals during startup. The NRC is willing to allow one satartup per calendar year without the RWM in order to avoid delays that may occasionally occur.

Ask the class what happens when the mode switch is placed in

the RUN mode.------->

Transfer of Mode Switch to RUN:

1. **Places New NMS scram and rod block setpoints in effect.**
2. **MSIVs will initiate a scram if closed.**
3. **MSIVs will close if vacumm low or steam line pressure is low**

Purpose of SLC—>>

SLC

To bring the reactor to a shutdown cold conditions, with all rods out and poison free.

Two SLC subsystems shall be operable.

SLC
3.1.7 Page 3.1-27
Bases Page B3.1-39

With the SLC concentration at 6.3% and volume at 3000 (Region B) gallons the sodium pentaborate solution must be restored to within region A limits in 72 hours AND 10 days from the discovery of failure to meet the LCO.

The standby liquid control system (SLC) provides a backup reactivity control capability to the control rods. The original design basis for the SLC system is to provide a soluble boron concentration to the reactor vessel sufficient to bring the reactor to a cold shutdown condition. In addition to the original design basis, the system must also satisfy the requirements of the ATWS Rule 10 CFR 50.62 paragraph (c) (4), which requires that the system have a control capacity equivalent to that for a system with an injection rate of 86 gpm of 13 weight percent unenriched sodium pentaborate, normalized to a 251 inch diameter reactor vessel.

The term "equivalent reactivity control capacity" refers to the rate at which the boron isotope B10 is injected into the reactor core. The SLC system meets this requirement by using a sodium pentaborate solution enriched with a higher concentration of B10 isotope. The minimum concentration limit of 6.2 percent sodium pentaborate solution is based on 60 atomic percent B10 enriched boron and a flow rate of 41.2 gpm.

Control Rods

Control Rods

The capability to insert control rods provides assurance that the assumptions for scram reactivity in the DBA and transient analyses are not violated. Since the SDM ensures the reactor will be subcritical with the highest worth control rod withdrawn (assumed single failure), the additional failure of a second control rod to insert, if required, could invalidate the demonstrated ADM and potentially limit the ability of the CRD System to hold the reactor subcritical. Therefore, the requirement that all control rods be operable ensures the CRD system can perform its intended function.

The control rods also protect the fuel from damage which could result in release of radioactivity. The limits protected are the MCPR Safety Limit (SL) and minimum critical power Ratio (MCPR), the 1% cladding plastic strain fuel design limit, APLHGR, and the fuel damage limit (LCO 3.1.6 "rod pattern control") during reactivity insertion events.

The negative reactivity insertion (scram) provided by the CRD system provides the analytical basis for determination of the plant thermal limits and provides protection against fuel damage limits during CRDA.

Limitations on inoperable rods is set so that the resultant effect on total rod worth and scram shape will be kept to a minimum. For a control rod to be considered inoperable, one of the following conditions must exist:

- Immovable due to excessive friction or mechanical interference, or known to be untrippable.
- Unable to meet scram times
- Scram accumulators inoperable
- Uncoupled control rod
- RPIS (rod position can not be determined).
- Not in BPWS when required

Stuck Rod
Bases A.1,A.2 and A.3
Page B3.1-15

A control rod is considered stuck if it will not insert by either CRD drive water of scram pressure. With a fully inserted control rod stuck, no actions are required as long as the control rod remains fully inserted.

3.1.4 Page 3.1-12

Control Rod Scram Times

Bases page B3.1-22

Requirements for the various scram time measurements ensure that any indication of systematic problems with control rod drives will be investigated on a timely basis. The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate. The resulting negative scram reactivity forms the basis for the determination of plant thermal limits.
The Scram function of the CRD System protects the MCPR Safety Limit (SL) and minimum critical power Ratio (MCPR), the 1% cladding plastic strain fuel design limit, APLHGR, which ensure that no fuel damage will occur if these limits are not exceeded. Above 800 psig, the scram function is designed to insert negative reactivity at a rate fast enough to prevent the actual MCPR from becoming less than the MCPR SL, during the analyzed limiting power transient.

3.1.5 Page 3.1-16
Control Rod Scram Accumulators

Control rods with inoperable accumulators are declared slow or inoperable. The specifications prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive pressure. Operability of the accumulator is based on maintaining adequate accumulator pressure. When one control rod scram accumulator becomes inoperable and the reactor pressure is >900 psig, the control rod may declared " slow", since the control rod will still scram at the reactor operating pressure but may not satisfy the scram times.

Bases Page B3.1-14
Last paragraph

The operability of an individual rod is based on a combination of factors, primarily, the scram insertion times, the control rod coupling integrity, and the ability to determine the control rod position. Accumulator operability is addressed by LCO 3.1.5. The associated scram accumulator status for a control rod only affects the scram insertion times; therefore, an inoperable accumulator does not immediately require declaring a control rod inoperble. Although not all control rods are required to satisfy the intended reactivity control requirements, strict control over the number and distribution of inoperable control rods is required to satisfy the assumptions of the DBA and transient analyses.

Control rod coupling integrity is required to ensure compliance with the analysis on the rod drop accident. Control rod position may be determined by the use of operable indicators, by moving control rods to a position with an operable indicator, or use other appropriate methods.

To ensure that the control rod patterns can be followed and other parameters are within their limits, the control rod position information system must be operable.

CRD Testing

CRD Testing

Diagnostic testing is the selective analytical testing of specific CRD mechanisms and associated HCUs based on a prior analysis of drive performance and base test data. Tests consists of CRD scram time testing, scram valve timing, stall flow, differential pressure tests, normal drive speeds, and electrical tests. Diagnostic testing limits maintenance outage time and problems with LCO requirements in technical specifications.

Testing will:

- Minimize corrective maintenance to drives with pre-analyzed need, thus maximum utilization of maintenance time.
- Minimizes CRD operational problems in future operating cycles, maximizing plant availability and flexibility.

If a CRD fails to respond to the normal insert/withdraw command signals, notch-in or out of "00", or exhibit scram problems, a differential pressure test should be performed. An analysis of traces generated by measuring the dp changes with an oscilloscope can isolate such faults as:

- CRD mechanical malfunction
- Improper operation of HCU directional control valves (leakage, blockage)
- Improper RMCS timer operation
- Unbalanced hydraulic system (stabilizing valves, flow and pressure control)
- Scram valve leakage
- Air in hydraulic lines
- Improper electrical relay operation

When it is initially determined that an analysis is needed, the following steps should be taken:

- Install testing equipment.
- Apply notch-in signal.

Use a camera to photograph the oscilloscope trace for documentation purposes and as a possible trouble shooting aid.

Normal Notch in

Figure 3.1-1 illustrates a notch in of a control rod drive. A surge pressure of approximately 140 psid is applied until the drive begins moving and drops to about 80 psi to maintain movement.

Air in System

Anytime the control rod drive system is open for maintenance a potential for trapping air in the system exists. In addition, accumulation of air from the CRD water supply over a period of time can occur.

Air in the CRD hydraulic system can result in the following problems:

- Loss of response at directional control valve switching points during the notch out cycle when the volume of air in the supply piping to the Po side increases.
- Loss of driving pressure dp response occurs during a notch-in or notch-out cycle when the volume of air in the supply piping to the Pu side increases. With only 35 in^3 of air trapped in the supply piping a failure to notch can occur.
- Air in the CRD hydraulic system piping can cause breakage of internal drive seals and primary stop piston seals.
- Oxygen is also a contributing cause of intergranular cracking.

Figure 3.1-2 illustrates a control rod being notched out from position 24 with air trapped in piping to the Po side. Note the loss of dp response at directional control valve switching points and the accumulator discharge effect occurring during the settle function.

Figure 3.1-3 illustrates a control rod with insufficient differential pressure to insert the drive. Several problems could cause a low differential pressure, however, in most cases the problem is associated with the hydraulic control unit. Some of the most obvious reasons are listed below.

- plugged filters
- failed closed insert directional control valve
- failed open withdraw directional control valve
- HCU valve line-up not correct
- severe seal damage to drive mechanism
- various electrical malfunctions that could prevent proper valve sequencing.

Summary

- **Before transferring the mode switch to the RUN position it is important that the interlocks are satisfied prior to mode transfer.**
- **Operability of the SLC system is verified by running the system and poison solution conditions.**
- **Inoperable control rods**
  - **Immovable due to excessive friction or mechanical interference, or known to be untrippable**
  - **Unable to meet scram times**
  - **Scram accumulators inoperable**
  - **Uncoupled rod**
  - **RPIS inoperable**
  - **Not in BPWS when required**

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Figure 3.2-1

Question for the Class
Why have thermal Limits?

3.2.1 Introduction

Limits on plant operation are established to assure the plant can be safely operated and not pose any undue risk to the health and safety of the public.

The objective for establishing thermal limits for normal operation and transient events is to maintain the integrity of the fuel cladding. This is done by limiting fuel rod power density to avoid over stressing the fuel cladding due to pellet-clad differential expansion, and to avoid centerline melting. Transition boiling must also be prevented to avoid cladding damage due to overheating.

The thermal limits established for these purposes are the ECCS/LOCA limit, the thermal-mechanical limit, and the minimum critical power ratio (MCPR) limit (Figure 3.2-1).

3.2.5 Exercise

A concerned nuclear engineer trainee at a facility expresses his concerns that the facility may not be operating within the thermal limits as defined by Technical Specifications.

The data available to you consists of the following:

- 2500 MW_{th} core operating at 90% CTP
- A GE9B (62 fuel rods, 150in. active fuel length) bundle producing 4.5 MW_{th}
- Node 16 producing 0.38MW_{th} (Uncontrolled)
- Critical power for the GE9B bundle is 6.5 MW_{th}
- Core Flow = 80%; NBUN = 560 bundles
- PTOPF = 0.995
- FLK + FCH = 0.04
- Attachment 1 (Last Core Operating Limits Report for the plant)
- Bundle exposure of 25 Gwd/st
- Operating limit MCPR = 1.32

With the aid of figures and this chapter determine if the plant is in violation of Technical Specifications. The information provided comes from the SNE manual and the Core Operating Limits Report.

The logical solution is to consult T/S for the required limits.

MCPR safety limit on page 2.0-1
Power Distribution limits:

- **APLHGR on page 3.2-1**
- **MCPR on page 3.2-2**
- **LHGR**

Thermal-Mechanical Limit

Mechanical Limit (1 % Plastic Strain)

The thermal expansion rates of the UO_2 pellets and zircalloy cladding are different. The relative expansion arises from several sources:

- UO_2 fuel thermal expansion coefficient is approximately twice that of zircalloy.
- Fuel pellets operate at higher temperature than the cladding.
- Fuel pellets undergo irradiation growth as they are exposed.
- Fuel pellets crack and redistribute toward the cladding when under thermal stress.

This contact places stress on the cladding, If the stress exceeds the yield stress of the cladding material, the cladding will crack. Cladding cracking due to differential expansion of the pellet and clad is prevented by placing a limit on the peak fuel pin power level which would result in 1% plastic strain on the clad. The 1% plastic strain limit itself is conservative. It has been shown that even at the design end of life exposure on the fuel cladding (most brittle condition), greater than 1% plastic strain on the clad is required for cladding failure. This limit is called the *mechanical* limit.

Thermal Limit (Center Line Melting)

Another limit on peak fuel pin power prevents centerline melting. During transient conditions, fuel pellet overpower occurs which must be limited to prevent centerline melting. This limit is called the fuel pellet *thermal* limit.

These two peak kw/ft limits are usually grouped together and called the *thermal-mechanical* limit.

Steady State Thermal-Mechanical Limit

The peak kw/ft limit is exposure dependent. The combined steady state limit is determined by the most limiting thermal or mechanical limit and is set by the manufacturer for each fuel type. The limit at zero exposure is 13.4 kw/ft for all GE fuel except GE8B, GE9B, GE10B, and GE11B, which have a 14.4 kw/ft limit. These limits start to decrease after approximately 15,000MWd/st. The zero exposure limit is called Linear Heat Generation Rate (LHGR) limit, by most Technical Specifications.

Figure 3.2-2 MAPLHGRLimit
T/S limit exceeded.

APLHGR Limit

In the event of a DBA LOCA, the heat stored in the fuel at the time of the event could significantly damage the fuel cladding. The criteria that must be satisfied during this event are given in 10 CFR 50.46. During the DBA LOCA, the core region is voided of liquid in a relatively short time (less than 30 seconds). With no coolant, the only mechanism for heat removal from the cladding is radiative heat loss. The elevated fuel cladding temperatures cause an increase in the rate of oxidation of the zircalloy by the high temperature steam. The chemical reaction becomes self-sustaining at approximately 2800 °F. Formation of zirconium oxide causes the cladding to become brittle. If the cladding temperature increases sufficiently (greater than 2200 °F) for extended length of time, the hot brittle fuel cladding could fragment by the quenching action when the ECCSs reflood the core.

The ECCS/LOCA limit and the thermal -mechanical limit can be combined into one number. The result is an exposure dependent curve of Maximum Average Planar Linear Heat Generation Rate limit ($MAPLHGR_{limit}$).

Current GE BWR MAPLHGR limits (as a function of exposure) are based on the most limiting value of either the ECCS/LOCA limits or the thermal-mechanical design limits. Since the thermal-mechanical design limit is included in the determination of the $MAPLHGR_{limit}$, it can not be exceeded if the $MAPLHGR_{limit}$ is met. General Electric has proposed and the NRC has agreed that the separate specification of the steady state thermal-mechanical limit in the Technical Specifications is redundant and can be eliminated. The $MAPLHGR_{limit}$ will continue to provide assurance that the limits in 10 CFR 50.46 will not be exceeded, and that the fuel design analysis limits defined in NEDE 24011-P-A (GESTAR-II) will be met. The steady state thermal-mechanical limits are incorporated by reference into GESTAR-II.

Figure 3.2-2 is an example of a typical $MAPLHGR_{limit}$ curve for 8x8 fuel. The general shape of the curve is produced by using the most limiting kw/ft value calculated for each of the previous criteria. A number of different factors contribute to the change in the curve:

- Changes in local peaking factor with exposure.
- Buildup of fission product gases inside the fuel rod increase the internal gas pressure and decrease the thermal conductivity of the gas pressure.
- Fuel pellet densification
- Response of the plant ECCSs during the DBA LOCA.

Important

The last concern requires plant specific analysis. Therefore, the curves may be slightly different for different plants even though the fuel type is the same.

PCT following a LOCA is primarily a function of the average heat generation rate of all the rods in a fuel assembly at any axial location and is dependent secondarily on the rod-to-rod power distribution within an assembly. The peak cladding temperature is calculated assuming an LHGR for the highest powered rod less than or equal to the design LHGR corrected for fuel densification.

The calculational procedure used to establish the APLHGR limits for Technical Specification is based on a loss-of-coolant accident analysis. The analysis was performed using General Electric calculational models which are consistent with the requirements in Appendix K to 10 CFR 50. The LOCA analysis was performed utilizing the new improved calculational model, SAFER/GESTR-LOCA. The analysis demonstrated that LOCAs do not limit the operation of the fuel. Therefore, the APLHGR limits for the fuel types shown in the Core Operating Limits Report are based on the fuel thermal-mechanical design criteria.

Modifications Associated with the APLHGR Limit

A flow dependent correction factor is applied to rated conditions APLHGR to assure that the 2200 ^{0}F PCT limit is complied with during a LOCA initiated from less than rated core flow. In addition, other power and flow dependent corrections are applied to rated conditions APLHGR limit to assure that fuel thermal-mechanical design criteria are preserved during abnormal transients initiated from off-rated conditions. The MAPFACs are defined separately as a function of power and flow.

$$MAPLHGR \times MAPFAC_p = MAPLHGR_p$$
$$MAPLHGR \times MAPFAC_f = MAPLHGR_f$$

The MAPLHGR is taken from a figure similar to Figure 3.2-2 for each fuel type, and the MAPFACs are taken from Figures 3.2-3 and 3.2-4. $MAPFAC_p$ is usually determined from feedwater controller failure event results. $MAPFAC_f$ is usually determined by the recirculation pump runout event results. Below P_{bypass}, there is significant sensitivity to core flow during transients. P_{bypass} is defined as the power level which a reactor scram on turbine stop valve position/turbine control valve fast closure is bypassed. For this reason the $MAPFAC_p$ is further defined separately for a high flow (> 50% core flow) and a low flow condition (≤ 50% core flow). Below 25% rated power, surveillance of thermal limits are not required,due to the very large operating margins. Therefore, the $MAPFAC_p$ graph is not addressed below 25% power.

For single loop operation, a multiplication factor is applied to the rated conditions APLHGR power and flow-dependent correction factors and the limiting values for APLHGR for each fuel type used in a particular cycle.

After the correction factors have been applied, the lowest MAPLHGR value is the $MAPLHGR_{limit}$ for that power and flow. These calculations are performed by the process computer.

MAPLHGR Determination

The process computer calculates the total power produced in every node in the core. A portion of the power produced in a node is produced outside the fuel pins by gamma heating and neutron moderation. This power is divided into two parts: The fraction of the total nodal power that is produced outside the fuel channel in the leakage flow (FLK) and the fraction of the total nodal power produced in the channel that is not conducted through the cladding (FCH). Therefore, for comparison to the $MAPLHGR_{limit}$, the average power density in a node is calculated as follows:

Calculation------>

$$MAPLHGR = \frac{Pnode * (1-FCK-FCH) * 1000 * PTOPF}{NRB * DZSEG}$$

where:

Pnode = Power produced in the node (MW)

= 0.38 MW_{th}

FLK = Fraction of core power deposited in leakage flow

FCH = Fraction of core power deposited in active channel flow by methods other than convection.

FLK + FCH = 0.04

PTOPF = Fraction of core thermal power generated in the bottom 144 inches of fuel.

= 0.995

NRB = Number of fuel rods per bundle.

= 62

DZSEG = Fuel segment length (ft)

= 0.5

MAPLHGR = 11.71 kw/ft

Figure 3.2-2,
$MAPLHGR_{limit}$ = 11.52

T/S limit exceeded
Must reduce power to <25% in 4 hours

$$MAPRAT = \frac{MAPLHGR}{(MAPLHGR_{limit})[\min(MAPFAC_p, MAPFAC_f)]}$$

$$= \frac{11.71 \text{ kw/ft}}{(11.52 \text{ kw/ft})(0.98)} \qquad \frac{11.71}{11.29} = 1.037$$

$$= \frac{11.71 \text{ kw/ft}}{(11.52 \text{ kw/ft})(0.95)} \qquad \frac{11.71}{10.94} = 1.07$$

Peak kw/ft Determination

The process computer calculates the peak kw/ft value for each fuel bundle node in the core. The full core power distribution program (P1) edits these values as MRPD (Maximum Rod Power Density).

MRPD = MAPLHGR x FLOP

FLOP = Maximum rod power/average rod power in a cross section of fuel segment (local peaking factor). Figure 3.2-8 for FLOP (local peaking factor)

MFLPD = 13.12/14.4
= 0.911

= 11.71 * 1.12

= 13.12 kw/ft

Once these peak nodal kw/ft values are calculated, the computer compares these to the zero exposure steady state thermal-mechanical limit of 13.4 kw/ft (or 14.4 kw/ft for GE8B, GE9B, GE10B, and GE11B). The process computer calls the steady state thermal-mechanical limit RPDLIM. The ratio of MRPD to RPDLIM is called Fraction of Limiting Power Density (FLPD). As long as the largest value of FLPD is less than one, we are assured that we have not exceeded the thermal limit.

CPR Safety Limit

Define CPR------>

Critical power is the fuel bundle power required to cause transition boiling somewhere in the bundle. The critical power ratio (CPR) of a fuel bundle is the ratio of its critical power to its actual operating bundle power. The minimum value of CPR for all fuel bundles in the core is the Minimum critical power ratio (MCPR) and represents the bundle which is the closest to transition boiling. **MCPR limits are imposed to avoid fuel damage due to severe overheating of the cladding.**

The required Operating Limit MCPRs (OLMCPRs) at steady state operating conditions are derived from the established fuel cladding integrity Safety Limit MCPR of 1.06 for two-loop operation and 1.07 for single-loop operation, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting as given in Technical Specifications. The Steady state MCPR thermal limit is derived from the single design basis requirement:

Transients caused by single operator error or equipment malfunction shall be limited so that, considering uncertainties in monitoring the core operating state, at least 99.9% of the fuel rods are expected to avoid boiling transition.

MCPR Calculation---------->

$$MCPR = \frac{\text{Critical Power}}{\text{Bundle Power}} \qquad \frac{6.5\ MW_{th}}{4.5\ MW_{th}}$$

$$= 1.44$$

Modifications Associated with the MCPR Limit

The current licensing basis approved with the GENESIS/ODYN models for calculating the OLMCPR for pressurization events is performed in accordance with either or both of two methods known as Option A and Option B. These currently used options are summarized below:

Option A

This approach is comprised of the two-step calculation which follows:

1. The pressurization transient is analyzed using the GENESIS/ODYN models to obtain the change in the critical power ratio (ΔCPR) for the core. Conservative input parameters are used in the analysis, (e.g. scram speed per Technical Specifications).

2. The licensing basis OLMCPR is given as OLMCPR = 1.044* (Safety Limit CPR + ΔCPR).

$$1.044(1.27) = 1.32$$

Option B

This procedure provides for statistical determination of the pressurization transient ΔCPR/(Safety Limit + ΔCPR) such that there is a 95% probability with 95% confidence (95/95) that the event will not cause the critical power ratio to fall below the MCPR Safety Limit. This approach can be satisfied in one of two ways:

1. A *plant-specific* statistical analysis can be performed per the approved statistical methodology procedures to determine the 95/95 ΔCPR/(Safety Limit +ΔCPR); or

2. Generic ΔCPR/(Safety Limit + ΔCPR) Statistical Adjustment Factors (SAF) for grouping of similar type plants can be applied to plant-specific calculations to derive the 95/95 ΔCPR/(Safety Limit +ΔCPR) value.

Utilities using Option B must demonstrate that their plant's scram speed distribution (τ_{ave}) is consistent with that used in the statistical analysis (τ_B). This is accomplished through an approved Technical Specification which requires testing and allows adjustment of the operating limit MCPR if the scram speed is outside the assumed distribution.

The GEMINI/ODYN set of methods has been compared against actual test data. The results of the comparison indicate an improvement in prediction accuracy with GEMINI/ODYN models. the true 95/95 ΔCPR/(Safety Limit + ΔCPR) will be determined using the same fundamental approach established for the current GENESIS/ODYN Option B and accounting for the improvement in prediction accuracy. The resulting procedure, which will be used with the GEMINI/ODYN models, simplifies the current two option approach into one.

Licensing analyses accomplished with GEMINI/ODYN models will permit plants to operate under a single set of MCPR limits if scram speed compliance procedures identical to those in current plant Technical Specifications are followed. If scram speed compliance is not demonstrated, more conservative MCPR operating limits must be met. The statistical determination of the transient ΔCPR/(Safety Limit +ΔCPR) factor for the pressurization event will continue to assure 95% probability with 95% confidence that the critical power will not fall below the MCPR Safety Limit.

The Technical Specification limit will be determined from the following general equation:

$$\text{OLMCPR}_{\text{Tech.Spec}} = \text{OLMCPR}_{95/95} + \frac{\tau_{avg} - \tau_s}{\tau_a - \tau_B}(\Delta\text{OLMCPR})$$

where:

$\Delta OLMCPR$ = factors derived by the new methodology

$OLMCPR_{95/95} = \Delta CPR_{95/95}$ + MCPR Safety Limit

For plants that demonstrate scram speed compliance (i.e. $\tau_{ave} \leq \tau_B$) using the NRC-approved procedures, the specification limit becomes:

$$OLMCPR_{TechSpec} = OLMCPR_{95/95} \text{ (for } \tau_{ave} \leq \tau_B)$$

If scram speed compliance is not demonstrated by a plant or if a plant chooses not to perform the scram speed compliance procedures (i.e. $\tau_{ave} \leq \tau_B$), then a more conservative limit must be used.

Figure 3.2-5

The actual operating limit will be a straight-line interpolation between these two values dependent on the results of scram speed testing, Figure 3.2-5.

At less than rated power conditions, transients such as Rod Withdrawal Errors, Feedwater Controller Failures, or recirculation pump runouts become limiting. For this reason, the OLMCPR is raised to compensate for such transients. These operating limits are:

$MCPR_f$ = a flow biased MCPR operating limit
$MCPR_p$ = a power biased MCPR operating limit (K_p power adjustment factor)

A flow adjusted factor (K_f) increases the CPR operating limit at core flows less than rated (Figure 3.2-6). The upper curve is used when operating in the automatic flow control mode to prevent violation of the OLMCPR if flow increases to the maximum flow rate allowed by the recirculation system. The lower curves are used when operating in the manual flow control mode to prevent violation of the safety limit MCPR if flow increases to the maximum flow rate allowed by the recirculation system.

When operating below P_{bypass} the severity of a limiting event becomes significantly sensitive to the initial flow at which the transient begins. A high initial flow is more limiting. Therefore, to prevent application of the more conservative high flow limits to a typical low flow startup condition, the $MCPR_p$ is further defined for high flow (> 50% core flow) and low flow conditions (≤ 50% core flow). The 50% cutoff for flow is a conservative value.

Since the initial core flow below P_{Bypass} affects the severity of the transient, the value taken from Figure 3.2-7 is the $MCPR_p$ and not the correction factor K_p. Below P_{Bypass}, the severity of events such as Load Reject without bypass or Turbine Trip without bypass can exceed that of a feedwater controller failure.

When operating at rated power and flow conditions, the OLMCPR is the limiting value for MCPR. However, at less than rated power and flow conditions, the $MCPR_f$ and $MCPR_p$ are determined and the largest value of the two becomes the OLMCPR for that power and flow condition.

The process computer calculates $MCPR_{limit}$ where:

$$MFLCPR_{limit} = \frac{\max[(Kp \text{ x } OLMCPR), MCPRf]}{MCPR}$$

(1.27) Figure 3.2-7

(1.07) Figure 3.2-6

$$\frac{\max[1.27(1.07 * 1.32)]}{1.44}$$

$$\frac{1.27}{1.44} = 0.88 \quad \textbf{or} \quad \frac{1.07 * 1.32}{1.44} = .981$$

In the new standard revised T/Ss a Sl violation is handled in section 2.0. The older TSs Sl violation is found in the administrative section 6.0

Learning Objectives
Viewgraph

3.3 CONTROL ROOM LOG 1

Learning Objectives:

1. Determine if any Technical Specification action statements are in effect.
2. Determine if any system addressed in the log is in an abnormal alignment.
3. Determine plant conditions relative to the instability region of the power/flow map.
4. Describe the basic method used to determine jet pump operability.
5. Describe the power condition with the most restrictive chloride limit.
6. Explain the need for PCIOMR restraints.
7. List the requirements for starting and operation of the recirculation pumps.

Introduction

Technical Specification chapter 3.3 consists of a typical control room log, Attachment A, that will require you to utilize Technical Specifications to address the learning objectives listed above.

Page 3.3-4
Viewgraph of P/F map
Have a student determine position of plant in relation to map and P/F map (100% rod line)

Lesson

Initial Conditions:

- Reactor Power at 62%
- Total Core Flow 57%
- 'B' RWCU is in the process of being precoated

PCIOMR

Time - 1610.
Briefly discuss PCIOR and background.

Preconditioning Interim Operating Management Recommendation (PCIOMR) discussion can be found in chapter 4.4 of this manual. Only a brief explanation of PCIOMR will be addressed here for the purpose of the control room log summary review.

PCIOMR is based on results of plant surveillance, fuel inspections, and individual fuel rod testing in the General Electric Test Reactor (GETR). Tests at GETR in 1971 and 1972 confirmed the mechanism and characteristics of the pellet clad interaction (PCI) failures observed in operating BWRs during rapid power increases. Beginning in 1972 test of production fuel rods demonstrated that a slow ascent to power would not only prevent failure, but that the slow ramp "preconditioned" the fuel to withstand subsequent rapid power changes at all levels up to that attained during the initial slow power increase.

For PCI to occur, both a chemical embrittling agent (fission products I and Cd) and high cladding stress are necessary. To eliminate the PCI problem General Electric introduced barrier fuel. However, recent experiences at BWRs indicate that if a fault (crack) exists it will propagate very rapidly at high power. Therefore, General Electric has implemented a revised PCIOMR at plants with small fuel failures to prevent the zipper effect on the cladding.

Time - 1615
Recirculation System

The term "zipper effect" is the terminology initiated by General Electric to identify the rapid propagation of a fuel cladding failure pertaining to barrier fuel.

Viewgraph of page 3.4-1 and 2 (3.4 Reactor Coolant System)

Recirculation System

Operation with a reactor coolant recirculation loop inoperable is allowed, provided that adjustments to the flow reference scram and APRM rod block setpoints, MCPR cladding integrity safety limit, OLMCPR, and MAPLHGR limit are made. The adjustments to APLHGR and the MCPR limits that are required for single loop operation are provided in the Core Operating Limits Report. The flow reference simulated thermal power setpoint for single loop operation is reduced by the amount of $m\Delta W$, where m is the flow reference slope for the rod block monitor and ΔW is the largest difference between two loop and single loop effective drive flow when the active loop indicated flow is the same. This adjustment is necessary to preserve the original relationship between the scram trip and actual drive flow.

The possibility of experiencing limit cycle oscillations during single loop operation is precluded by restricting the core flow to greater than or equal to 45% of rated when core thermal power is greater than the 80% rod line.

Time -1725

Chemistry

The Chemistry requirements were moved from the technical specifications manual to the technical requirements manual in the new revised technical specification. Viewgraphs of pages need to be shown.

Chemistry

The water chemistry limits of the reactor coolant system are established to prevent damage to the reactor materials in contact with the coolant. Chloride limits are specified to prevent stress corrosion cracking of the stainless steel. The effect of chloride is not as great when the oxygen concentration in the coolant is low; thus the higher limit, 0.5 ppm, on chlorides is permitted during full power operation. During shutdown and refueling operations the temperature necessary for stress corrosion to occur is not present.

Ask the class for the place where continuous monitoring of reactor water is accomplished. Conductivity is continuously monitored via the RWCU system, inlet to the F/Ds.

Conductivity measurements are required on a continuous basis since changes in this parameter is an indication of abnormal conditions. When the conductivity is within limits, the pH, chloride and other impurities affecting conductivity must also be within their acceptable limits. With the conductivity meter inoperable, additional samples must be analyzed to ensure that the chlorides are not exceeding the limits.

In addition to chemistry limits, what other parameter deals with reactor water quality. (Page 3.4-14)

Specific activity of the reactor coolant system ensures that the two hour thyroid and whole body dose resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the guidelines of 10 CFR Part 100 limits.

Time - 1845
page 3.4-23
Bases B3.4-48

Idle Recirculation Loop Startup

When restarting an idle pump, the discharge valve of the idle loop is required to remain closed until the speed of the faster pump is below 50% of its rated speed to provide assurance that when going from one to two loop operation, excessive vibration of the jet pump risers will not occur.

In order to prevent undue stress on the vessel nozzles and bottom head region the recirculation loop temperatures shall be within 50 °F of each other prior to startup of a an idle loop. Since the coolant in the bottom of the vessel is at a lower temperature than the water in the upper regions of the core, undue stress on the vessel would result if the temperature difference were greater than 145 °F. The loop temperature must be within 50°F of the reactor vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles.

Time - 2013 seal alarm
Page 3.4-9
3..4. RCS Operational Leakage
B3.4-18

Operational Leakage

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for unidentified leakage the probability is small that the imperfection of cracks associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the value specified or the leakage is located and known to be pressure boundary leakage the reactor will be shutdown to allow further investigation and corrective action.

Time - 2324

Jet Pump Operability

It is important to verify that reactor operation is always consistent with the licensing basis. As part of the licensing basis, it assumes that the jet pumps are operating as designed because they contribute in the ability to re-flood the core to two-thirds core height and are a path for low pressure coolant injection flow into the reactor vessel (were applicable). Blockages in the recirculation loop would significantly decrease injection flow. Another important aspect is to recognize potential problems as soon as possible so as to minimize equipment damage and increase plant availability. Therefore, it is important to establish that the jet pumps are operable by monitoring their performance routinely.

The major instrumentation used for performance monitoring are the recirculation pump speed, recirculation pump flow, individual jet pump flow, jet pump loop flow, core flow and core plate differential pressure.

The principle method used is to compare actual conditions against expected conditions is daily record keeping. Such a method depends on instrument repeatability. This requires the accumulation of a "normal" data base for comparison to current operation. The most important part of this method is to always use the same instrument used to obtain the data base. This method also makes instrument calibrations critical.

Core flow versus square root core plate differential pressure, recirculation pump flow versus speed, jet pump flow versus recirculation pump speed and jet pump flow in differential pressure relationships are the most commonly used performance measures.

For illustrative purposes, the jet pump flow (differential pressure) relationship is discussed as a performance monitoring parameter. Individual jet pumps in a recirculation loop do not have the same flow. The unequal flow is due to:

- the drive flow manifold which does not distribute flow equally to all risers.
- individual jet pump manufacturing and installation tolerances.
- the flow resistance the jet pump encounters in the lower plenum and vessel annulus.

The flow (differential pressure) pattern or relationship of one jet pump to the loop mean is repeatable and is influenced by natural circulation at low core flow rates.

In addition, for constant drive flow, the jet pump inherently will not operate at a constant flow but will fluctuate over a flow range of about 5 percent. Further, due to the turbulence in the jet pump diffuser where the flow measurement pressure tap is located, the differential pressure signal is usually noisy when the jet pump is in operation. The constant motion of the individual jet pump flow indicators makes data acquisition difficult. However, the noise is the most positive indication that the jet pump is operating. A typical jet pump flow deviation relationship along with the acceptance criteria are shown in Figure 3.3-1.

3.4 CONTROL ROOM LOG 2

Learning Objectives:

1. Determine if any Technical Specification action statements are in effect.

2. Determine if any systems addressed in the log is in an abnormal alignment.

3. Determine plant status relative to power/flow map.

4. Explain the difference between an automatic isolation valve and a manual isolation valve.

Allow students approximately 25 minutes to determine LCO and answer lesson objectives.

Introduction

Technical Specification chapter 3.4 consists of a typical control room log, Attachment A, that will require you to utilize Technical Specifications to address the learning objectives listed above.

Exercise

Attachment A represents a typical control room log at a BWR/4. With the aid of Technical Specifications and this text, answer the learning objectives.

Learning Objective

3. Determine plant status relative to power/flow map.

If reactor power is 90% and core flow is 100% then the unit is on the 90% rod line.

3.4.1 Pump and Valve Testing

Viewgraph of Safety Class 1, 2 and 3

Technical Specifications Section 5.5.6 specifies that inservice inspections of ASME Code Class 1, 2, and 3 components must be conducted. It also ensures that the pump and valves inspection will be performed in accordance with a periodically updated version of section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50, Section 50.55a. Exemptions from any of the above requirements has been approved in writing by the Commission and is not a part of these Technical Specifications.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications and to remove any ambiguities related to the frequencies for performing the required inservice inspection and testing activities.

With the aid of HPCI Figure 3.4-1, probe student knowledge of system. BASES in TS is source for basic system information.

3.5.1 C and D LCO viewgraph page 3.5-1 and 2

SR 3.5.1.8 page 3.5-4
SR3.5.1.9 page 3.5-5

3.4.2 High Pressure Coolant Injection

The High Pressure Coolant Injection (HPCI) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the nuclear system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. HPCI system continues to operate until reactor vessel pressure is below the pressure at which LPCI system operation and Core Spray system operation can maintain core cooling. HPCI system capacity, 4250 gpm at 1135 and 165 psig, is selected to provide this required cooling.

With the HPCI system inoperable, adequate core cooling is assured by *operability* of the redundant and diversified Automatic Depressurization System (ADS) and the low pressure ECCSs. In addition, the Reactor Core Isolation Cooling (RCIC) System, system for which no credit is taken in the accident analysis, will automatically provide makeup at high reactor pressure. The Technical Specifications allowable out of service period of 14 days is based on the demonstrated operability of redundant and diversified low pressure ECCSs.

The surveillance requirements provide adequate assurance that the HPCI system will be *operable* when required.

3.4.3 Automatic Depressurization System

Upon failure of the HPCI system to function properly after a small break LOCA, the ADS automatically causes selected safety relief valves to open, depressurizing the reactor so that flow from the low pressure ECCSs can enter the core in time to limit fuel cladding temperature to less than 2200 ^{0}F. ADS is conservatively required to be operable whenever reactor pressure exceeds 150 psig even though low pressure ECCSs provide adequate core cooling up to 350 psig.

ADS automatically controls seven selected safety-relief valves although the accident analysis only takes credit for six valves. It is therefore appropriate to permit one valve to be out-of-service for 14 days without materially reducing system reliability.

ADS accumulators are sized such that, following loss of the pneumatic supply, at least two valve actuation will be possible with the drywell at 70% of its design pressure. The allowable accumulator leakage criterion ensures the above capability for 30 minutes following loss of the pneumatic supply.

With aid of RCIC transparency, probe students knowledge of system.

3.4.4 Reactor Core Isolation Cooling System

Page 3.5-12
SR 3.5.3.3

The Reactor Core Isolation Cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the ECCSs. The RCIC system is conservatively required to be operable whenever reactor pressure exceeds 150 psig even though the RHR system provides adequate core cooling up to 350 psig.

The RCIC system specifications are applicable during CONDITIONS 1, 2, and 3 when reactor pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

Two sources of water are available to the RCIC system. Suction is initially taken from the condensate storage tank and is automatically transferred to the suppression pool upon low CST level or high suppression pool level.

With RCIC inoperable, adequate core cooling is assured by the demonstrated operability of the HPCI system and justifies the specified 14 day out-of-service period.

Probe student knowledge of RHR modes with use of RHR figures.

Low Pressure Coolant Injection

Use Table T7.0-1 from technical requirements manual, point out how to read table and indicate the RHR valve in question.

Cover RHR mode for both operating and shutdown.

The LPCI mode of the Residual Heat Removal System is provided to assure that the core is adequately cooled following a LOCA. Two subsystems, each with two pumps, provide adequate core flooding for all break sizes from 0.2 ft^2 up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization. LPCI system specifications are applicable during conditions 1, 2 and 3 because LPCI is a primary source of water for flooding the core after the reactor vessel is depressurized.

When in conditions 1, 2, or 3 with one LPCI pump inoperable or one LPCI subsystem inoperable, adequate core flooding is assured by the operability of the redundant LPCI pumps or subsystems and both CS subsystems. The reduced redundancy justifies the specified 7 day out-of-service period.

3.5.2 ECCS - Shutdown

B3.5-17

ECCS - Shutdown

Two low pressure ECCS injection/spray subsystems are required to be operable. The subsystems consists of two CS subsystems and two LPCI subsystems. Each CS subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or CST to the reactor vessel. Each LPCI subsystem consists of motor driven pump, piping, and valves to transfer water from the suppression pool to the reactor vessel. Only a single LPCI pump is required per subsystem because of the larger injection capacity in relation to CS subsystem. In mode 4 and 5 the RHR crosstie valve is not required to be closed.

RHR S/D cooling mode page 3.4-16

Learning Objective 1

One LPCI subsystem maybe aligned for decay heat removal and considered operable for the ECCS function, if it can be manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable.

RHR Shutdown Cooling System - Hot Shutdown

3.4.7 page 3.4-16

B3.4-34

With the suction valve open and the possibility of not being able to be closed, could put the plant in action statement 3.4.7. Obviously with the plant in mode 1 this does not apply. However, one should keep in mind that the RHR system has many mode which are designed for various plant conditions and by changing operating modes may have an effect of the systems operability.

Section 3.4.7 RHR S/D cooling (Hot Standby) of 3.4 Reactor Coolant System

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products which increases the temperature of the reactor coolant. This decay heat must be removed to reduce the temperature ≤212°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Hot Shutdown condition.

The two redundent, manually controlled shutdown cooling subsystems of the RHR system provide decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. Two RHR shutdown cooling subsystems are required to be operable, and when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An operable RHR shutdown cooling subsystem consists of one operable pump and associated heat exchanger, piping and valves which can provide the capability to reduce and maintain temperature <212°F.

3.4.8 page 3.4-19

B3.4-40

Section 3.4.8 RHR S/D cooling (Cold Standby) of 3.4 Reactor Coolant System

In Mode 4, one RHR shutdown cooling subsystem can provide the required cooling (sufficient to maintain coolant temperature, <212°F, but two subsystems are required to be operable to provide redundancy. Operation of one subsystem can maintain or reduce coolant temperature as required. However, to ensure adequate core flow to allow for accurate average coolant temperature monitoring, nearly continuous operation is required.

Suppression Chamber

The operability of the suppression chamber in conditions 1, 2, or 3 is required by specification 3.6.2.1 of Technical Specifications. The suppression pool is designed to absorb the decay heat and sensible energy released during a reactor blowdown from safety/relief valve discharges for from design basis accidents. The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident. This is the essential mitigative feature of pressure suppression containment that ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs. The suppression pool must also condense steam from steam exhaust lines in the HPCI and RCIC systems. **Technical concerns that lead to the development of suppression pool average temperature limits are :**

a. Complete steam condensation;
b. Primary containment peak pressure and temperature;
c. Condensation oscillation loads; and
d. Chugging loads.

Chugging Loads
Is the cyclic condensation of steam in the downcomers that is determined by wetwell pressure.
Spray wetwell before 9 psig
Spray drywell after 9 psig
The 9 psig assumes that you have > 95 % steam in drywell which is < 5% non-condensibles.

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses initial suppression pool temperature and water volume. An initial pool temperature of 110^{0}F is assumed for analyses. Reactor shutdown at a pool temperature of 110^{0}F and vessel depression at a pool temperature of 120^{0}F are assumed. **The limit of 105^{0}F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during unit testing.**

Average temperature $\leq$100^{0}F when any operable intermediate range monitor channel is > 25/40 divisions of full scale on range 7 and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.

Average temperature $\leq$105^{0}F when any operable intermediate range monitor channel is > 25/40 divisions of full scale on range 7 and testing that adds heat to the suppression pool is being performed. This required value ensures that the unit has testing flexibility, and was selected to provide margin below 110^{0}F limit at which reactor shutdown is required.

Average temperature $\leq$110^{0}F when any operable intermediate range monitor channel is > 25/40 divisions of full scale on range 7. This requirement ensures that the unit will be shutdown at > 110^{0}F. Note that 25/40 divisions of full scale on IRM range 7 is a convenient measure of when the reactor is producing power essentially equivalent to 1% power.

Repair work might require making the suppression chamber inoperable. Therefore it is permitted to drain the suppression pool in condition 5.

The suppression chamber water provides the heat sink for the reactor coolant system energy release. The suppression pool volume ranges between approximately 86,000 ft^3 at the low water level limit of 146 inches and approximately 90,000ft^3 at the high water level limit of 150 inches.

If the **suppression pool water level is to low**, an insufficient amount of water would be available to adequately condense the steam from S/RV quenchers, main vents, or HPCI and RCIC turbine exhaust limes. Low suppression pool water level could also result in an inadequate emergency makeup water source to the ECCSs. The lower volume would also absorb less steam energy before heating up excessively.

If the **suppression pool water level is too high**, it could result in insufficient volume to accommodate noncondensable gases and excessive pool swell loads during a DBA LOCA. Therefore, a maximum pool water level is specified.

3.4.7 Primary Containment Isolation Valves

The operability of the primary containment isolation valves ensures that the primary containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the primary containment atmosphere or pressurization of the containment. Primary containment isolation within the time limits specified ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA. Automatic isolation valves are valves that receive automatic signals either from isolation logic or system operational signals. Manual containment isolation valves are valves that receive no automatic closure signals and are closed either remotely from the control room or locally at the valve.

3.4.8 Line Communication with Primary Containment

Several lines which penetrate the containment and communicate with its atmosphere are provided with isolation valves outside primary containment, rather than one isolation valve inside and one isolation valve outside primary containment. This deviation from GDC is considered safe and adequate because:

A. Lines which penetrate the containment for atmosphere sampling or processing terminate at the inboard end of the weld, within the drywell penetration sleeve. The sleeve and the piping connect to it on Seismic Category I, Quality Group B up to and including at least the second primary containment isolation valve.

   Installation of the inboard isolation valve inside primary containment would require supporting the valves from the drywell shell, resulting in additional welds, and/or extending the piping, and adding supports from other structural members within the drywell. Since these valves inside would severely impede accessibility for inspection and maintenance of the valves and other equipment.

B. Placing the valves inside the containment would subject them to an inimical environment and, thus, increase the probability of failure. The environment within the drywell and suppression chamber post-LOCA could be especially detrimental to the operation of the drywell and wetwell spray valves, since these valves would be required to function during the postulated containment pressure transient. The design spray coverage further necessitates the location of the spray header as close as practical to the interior of the drywell and wetwell shells.

Therefore, the isolation calves for each spray header is installed outside of primary containment. The outboard barrier is the closed RHR system. In addition to the two barriers required by GDC 56, the wetwell and drywell spray lines each have a motor operated valve installed inboard of the containment isolation valves. This design reflects the importance of avoiding an inadvertent initiation of containment sprays during plant operation. These valves also contribute additional conservatism to the containment isolation provisions since they shut, if open upon receipt of the LOCA initiation signal.

C. Valves are accessible in systems which must be available for long-term operation following an accident.

D. Isolating valves installed outside primary containment are compatible with minimizing personnel exposure during maintenance and inspections. Isolation valves for this category of line are either locked closed, administratively close, or are automatically closed upon receipt of an isolation signal.

The isolation valves in each line are installed as close together and as close to the primary containment as practical.

Influent Lines to Suppression Pool

The reasons for not placing valves inside the suppression chamber (pool) are similar to those already mentioned. The following discussion provides unique considerations as to the types of valves and isolation capabilities:

The RCIC and HPCI turbine exhaust lines, HPCI turbine condensate line, and RCIC vacuum pump discharge line. These line penetrate the wetwell and discharge below the minimum water level. Two primary containment isolation valves are provided outside the wetwell on each line. The inboard isolation valve for each line is a motor operated locked open globe stop check valve. When in its normal position, open, the valve allows flow into the suppression pool. The valve may be manually closed, from the control room, for long term leakage control. The outboard valve is a simple swing check valve and functions as a redundant isolation valve to ensure backflow from the suppression pool is prohibited.

Since HPCI and RCIC are ESF systems, check valves are used as isolation valves to optimize system operability.

Minimum Flow and Test Lines

These lines have isolation capabilities which are commensurate with the importance to safety of isolating these lines. The HCPI and RCIC minimum flow lines have two valves in series, both located outside containment. The RHR and CS minimum flow lines also have two isolation valves. One isolation valve is motor operated and the other is a swing check valve.

The core spray test line has a single automatic isolation valve installed outside primary containment. The core spray system is a closed system therefore, the system is the second isolation barrier and no further isolating is required. The residual heat removal system test line is has a single automatic isolation valve outside primary containment and also is a closed system, therefore it too requires no other isolation valves.

Effluent Lines from Suppression Pool

It should be noted that GDC 56 does not reflect consideration of the BWR containment design. Certain lines, such as the RHR, CS, HPCI and RCIC suction lines, penetrate below the water line and therefore, do not communicate with the containment atmosphere. These lines do have an isolation valve located inside containment, under water. This would result in introducing a potentially unreliable valve in a highly reliable system, thereby compromising design. For this reason, these line incorporate isolation valves outside the containment.

3.4.10 Additional differences/problems with other technical specifications.

Suppression pool level and temperature limits are found in different section in the standard/custom technical specifications. In Section 3/4.5, emergency core cooling systems, under depressurization systems suppression chamber the minimum and maximum water level limits are found. In order to find the water temperature limits you will have to go to section 3/4.6, containment systems, under suppression chamber. In addition, the containment isolation valves are listed in technical specifications section 3/4.6.3, primary containment isolation valves. In this section the automatic and manual isolation valves are found. Remembering that automatic isolation valves only means that the valves receive an automatic signal to close, which could be a system signal or to an isolation signal.

Manual containment isolation valves are valves that receive no automatic closure signals and are closed either remotely from the control room or locally at the valve.

Attachment A
Control Room Log

Safety Limit Violation
Page 2.0-1 viewgraph

This was in admin section in other T/Ss

3.5.5.3 Safety Limit Violation

The following actions shall be taken in the event a safety limit is violated:

- Within 1 hour, notify the NRC Operation Center, in accordance with 10 CFR 50.72.
- Within 2 hours:
  Restore compliance with All SLs; and
  Insert all insertable control rods.
- Within 24 hours, notify the plant manager, the corporte executive responsible for overall plant safety, and the offsite review committee.
- Within 30 days, a LER shall be prepared pursuant to 10 CFR 50.73. The LER shall be summitted to the NRC, the offsite review committee, the plant manager, and corporate executive responsible for overall plant nuclear safety.
- Opeartion of the unit shall not be resumed until authorized by the NRC.

Viewgraph of page 5.0-6

3.5.5.1 Procedures

Written procedures shall be established, implemented and maintained covering the activities referenced below:

- The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.
- Refueling operations.
- Surveillance and test activities of safety related equipment.
- Security Plan implementation
- Emergency Plan implementation
- Fire Protection Program implementation
- Process Control Program implementation
- ODCM implementation

Appendix A, Regulatory Guide 1.33

Appendix A, of Regulatory Guide 1.33, list typical safety related activities that should be covered by written procedures. This appendix is not intended as an inclusive listing of all needed procedures since many other activities carried out during the operation phase of nuclear power plants should be covered by procedures not included in this list.

Page 5.0-19 Viewgraph

3.5.5.2 Reportable Event Action

The following actions shall be taken for reportable events:

- The commission shall be notified and/or a report submitted pursuant to requirements of section 50.73 to 10 CFR part 50, and
- Each reportable event shall be reviewed by the PRB, and the results of this review shall be submitted to the SRB, the General Manager - Nuclear Plant, and the Vice President - Nuclear.

Viewgraph of page 3.3-21

Page 5.0-16

5.5.11

T.S Bases Control Program

3.5.3.5 Two-out-of-Four Voter

The Two-out-of-Four Voter Function provides the interface between the APRM Functions and the final RPS trip system logic. As such, it is required to be OPERABLE in the MODES where the APRM Functions are required and is necessary to support the safety analysis applicable to each of those Functions. Therefore, the Two-out-of-Four Voter Function is required to be OPERABLE in MODES 1 and 2.

All four voter channels are required to be OPERABLE. Each voter channel also includes self-diagnostic functions. If any voter channel detects a critical fault in its own processing, an Inop trip is issued from that voter channel to the associated trip system.

There is no Allowable Value for this Function.

3.5.4 Feedwater and Main Turbine High Water Level Instrumentation

The feedwater and main turbine high water level trip instrumentation is assumed to be capable of providing a turbine trip in the design basis transient analysis for feedwater controller failure, maximum demand event. The high level trip indirectly initiates a reactor scram from the main turbine trip (above 30% power) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

3.5.5 Administrative Controls

The General Manager - Nuclear Plant shall provide direct executive oversight over all aspects of the plant. The Assistant General Manager-Plant Operations shall be responsible for overall unit operation, and delegates, in writing the succession of this responsibility. A staff of Shift Supervisors, each licensed as Senior Reactor Operator (SRO), reports to the Assistant General Manager-Plant Operations and carries on-shift management responsibilities for safe operation of the plant. The Operating Supervisor is the SRO in charge of reactor operations on shift. Normally the Operating Supervisor stands watch in the control room, however, he/she may leave when the Shift Supervisor is present in the control room. The Shift Supervisor is responsible for all site activities in the absence of the Plant manager or designated alternates.

3.5.3.3 APRM Fixed Neutron Flux High

The Average Power Range Monitor Neutron Flux—High Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure. For the overpressurization protection analysis of Reference 4, the Average Power Range Monitor Neutron Flux—High Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 7) takes credit for the Average Power Range Monitor Neutron Flux—High Function to terminate the CRDA.The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

The Average Power Range Monitor Neutron Flux—High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor Neutron Flux—High Function is assumed in the CRDA analysis, which is applicable in MODE 2, the Average Power Range Monitor Neutron Flux—High (Setdown) Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Range Monitor Neutron Flux—High Function is not required in MODE 2.

3.5.3.4 APRM Inop

This Function (Inop) provides assurance that the minimum number of APRM channels is OPERABLE. For any APRM channel, any time: 1) its mode switch is in any position other than "Operate," 2) an APRM module is unplugged, or 3) the automatic self-test system detects a critical fault with the APRM channel, an Inop trip signal is sent to all four voter channels. Inop trips from two or more unbypassed APRM channels result in a trip output from all four voter channels to their associated trip system.

This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis. There is no Allowable Value for this function. This function is required to be OPERABLE in the MODES where the APRM Functions are required.

fuel design include an evaluation of the time constant to determine if the electronic filter requires replacement. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed APPLICABILITY control rod pattern) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Neutron Flux—High Function Allowable Value.

The Average Power Range Monitor Simulated Thermal Power—High Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and protects the fuel cladding integrity by ensuring that the MCPR SL is not exceeded. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Neutron Flux—High Function will provide a scram signal before the Average Power Range Monitor Simulated Thermal Power—High Function setpoint and associated time delay are exceeded. Each APRM channel uses one total drive flow signal representative of total core flow. The total drive flow signal is generated by the flow processing logic, which is part of the APRM channel. The flow is calculated by summing two flow transmitter signals, one from each of the two recirculation loop flows. The flow processing logic OPERABILITY is part of the APRM channel OPERABILITY requirements for this Function.

The clamped Allowable Value is based on analyses that take credit for the Average Power Range Monitor Simulated Thermal Power—High Function for the mitigation of the loss of feedwater heating event. The time constant is based on the fuel heat transfer dynamics and provides a signal proportional to the THERMAL POWER.

The Average Power Range Monitor Simulated Thermal Power—High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

Cover Control Rod Block Instrumentaion with aid of Viewgraphs Pages 3.3-15 to 20

When covering rod blocok instraumentation, point out MCPR requirement associated with RBM

3.5.3.1 APRM Neutron Flux—High (Setdown)

For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux—High (Setdown) Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux—High (Setdown) Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux—High Function because of the relative setpoints. With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux—High (Setdown) Function will provide the primary trip signal for a corewide increase in power. No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux—High (Setdown) function. However, this function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed 25% RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 25% RTP.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

The Average Power Range Monitor Neutron Flux—High (Setdown) Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists.

In MODE 1, the Average Power Range Monitor Neutron Flux—High Function provides protection against reactivity transients and the RWM and rod block monitor protect against control rod withdrawal error events.

3.5.3.2 APRM Flow Biased Simulated Thermal Power High

The Average Power Range Monitor Simulated Thermal Power—High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. Changes to

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters. The limiting safety system settings are defined as the allowable values, which, in conjunction with LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits, including safety limits during design basis accidents.

Functional diversity is provided by monitoring a wide range of ***dependent and independent*** parameters.

Table 3.3.1.1-1 Viewgraph

Average Power Range Monitor

3.5.3 Average Power Range Monitor

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. The APRM System is divided into 4 APRM channels and 4 two-out-of-four voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The APRM System is designed to allow one APRM channel, but no voter channels, to be bypassed. A trip from any one unbypassed APRM will result in a "half-trip" in all four voter channels, but no trip inputs to either RPS trip system. A trip from any two unbypassed APRM channels will result in a full-trip in each of the four voter channels, which in turn results in two trip inputs into each RPS trip logic channel (A1, A2, B1, and B2). Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal.

i.e APRM - incor
Page B 3.3-~~22~~ 7

In addition, to provide adequate coverage of the entire core, consistent with the design bases for APRM functions, at least 17 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, are required for each APRM channel.

At least ~~17~~ 11 LPRM inputs, with at least three LPRM inputs per level

3.5 Control Room Log #3

Learning Objectives Viewgraph===>>

Learning Objectives:

1. Determine if any Technical Specification action statements are in effect.

2. Determine if any systems addressed in the introduction are in an abnormal alignment.

Introduction

Have the class read the introduction section and answer the learning objectives (30 minutes)

3.5.1 Introduction

During this technical specification session the limiting conditions for operation, bases, and application of limiting conditions for operation are addressed for the Instrumentation and Administrative controls sections.

During your control room tour at about 0800 hours, with the plant at 93% power and in the run mode, you identify the following conditions:

- One RFP/MT high water level trip circuit inop
- LPRM 32-39A high alarm

After the class works through the problem, start the discusion by asking why an LPRM high MIGHT cause the associated APRM ot reach the rod block or scram setpoint.
(i.e.: Low reading LPRM failing high produces large change)

During further review of the logs you find that APRM-B was bypassed at 0019, as a result of a LPRM that failed high and causing ~~a half scram~~ APRM-B TRIP. The operators bypassed the APRM and logged the event in the degraded equipment log. In addition, you were ask to resolve a discussion between two operators concerning the requirement(s) to make a change to the bases of technical specifications.

From the above information and the aid of technical specification, address the learning objectives.

Ask for purpose of the Reactor Protection System

Page B 3.3-4 3P

No. RPS Function Required in Modes 3 & 4

3.5.2 Reactor Protection System

The Reactor Protection System (RPS) initiates a reactor scram when one or more monitored parameters exceed their specified limits, to preserve fuel cladding integrity, reactor coolant system integrity, and minimize the energy which must be absorbed following a LOCA.

ANTICIPATED TRANSIENT WITHOUT SCRAM (ATWS)

Learning Objectives

Learning Objectives:

1. Define anticipated transient without scram.

2. Explain the expected plant response for the worst ATWS event.

3. List the scram signals received during the initial ATWS event.

4. Explain why an ATWS event is safety significant.

5. List various ways to limit core power during an ATWS event.

Introduction

Define abnormal transients

- Have the class provide a list of abnormal transients.

In general, the term reactor transient applies to any significant deviation from the normal operating value of any of the key reactor operating parameters. Transients may occur as a consequence of an operator error or the malfunction or failure of equipment.

Anticipated transients are deviations from the normal operating conditions that may occur one or more times during the service life of a plant. Anticipated transients range from trivial to significant in terms of the demands imposed on plant equipment. Anticipated transients include such events as a turbine trip, EHC failure, MSIV closure, loss of feedwater flow and loss of feedwater heating. More specifically, all situations (except for LOCA) which could lead to fuel heat imbalances are anticipated transients.

Objective 1

Many transients are handled by the reactor control systems, which would return the reactor to its normal operating conditions. Others are beyond the capability of the reactor control systems and require reactor shutdown by the Reactor Protection System (RPS) in order to avoid damage to the reactor fuel or coolant systems. If such a transient should occur and if, in spite of all the reliability built into the Reactor Protection System, a scram should not result, then an ATWS event would have occurred.

Ask the class to consider the events listed, compare two, eliminate the one that is not as sever as the other, and explain why.

Of the transients list, you should end up with at least two on the board.

Significant ATWS events

The transients having the greatest potential for fuel damage are loss of condenser vacuum and full MSIV closure.

- Loss of condenser vacuum causes automatic closure of the turbine SVs, CVs , and BPVs. Closure of the turbine valves and bypass valves increases reactor pressure and power. The neutron flux spike is limited to about 392% due to the large steam line volume available to buffer the pressure spike.

- MSIV closure is slower than the turbine trip without BPVs, but the large steam line volume does not exist. Without the extra volume pressure rise produces a power spike of 527%.

The probability of MSIV closure was $3.0x10^{-5}$ per demand. This is a low value but the MSIVs full closure happened on the average of 1.5 times per year per plant . (Data good up to the 90s). Surveillance from high rad and steam line area temperatures were the most common events. If you combine this with common mode failures to scram it becomes a significant event.

- maintenance of relays
- maintenance of CRDMs
- maintenance of scram solenoids
- Hydraulic lock

History

ATWS became a possible source of concern in nuclear power plants in 1968 during discussions between ACRS, the regulatory staff, and reactor instrument designers about the safety implications of interactions between normal control system circuitry and protection system circuitry in the instrument systems of power plants. After considerable discussion and some design changes, it was determined that separation of control and protection functions was being achieved to a reasonable degree, either by physical separation or by electrical isolation. The focus of interest with regard to instrument systems then shifted to the ability of the shutdown system to function with the needed reliability considering common mode failures. Common mode failures have to do with design or maintenance errors that might be made for similar redundant portions of a protection system. One of the difficult aspects of deciding whether or not common mode failures were being adequately accounted for in shutdown system design was that techniques to analyze a system for common mode failures were not as well developed as techniques to analyze a system for random failures.

1969

The efforts to evaluate the safety concerns of ATWS events went in two general directions. The first was concerned with attempting to evaluate the likelihood of common mode or other failures of the reactor protection system that could lead to ATWS events. The second was to assume, simply as a basis for discussion, that ATWS was possible and to examine the consequences of various postulated ATWS events.

1970

After analyzing vender supplied information it was concluded that several anticipated transients in BWRs would require prompt action to shutdown the reactor in order to avoid serious plant damage and possible offsite release. The resulting list of transients considered for boiling water reactor plants is as follows:

- **Primary Pressure Increase**

These transients include loss of load events such as generator trip, turbine trip, and loss of condenser vacuum. Also considered are such transients as closure of one or all of the main steam line isolation valves and malfunction of the reactor primary system pressure regulator, causing increasing pressure.

- **Reactor Water Inventory Decrease**

These transients include events leading to a decrease in the inventory of reactor primary coolant such as loss of auxiliary power, loss of feedwater, pressure regulator failure in a direction to cause decreasing reactor system pressure, inadvertent opening of a safety or relief valve, and opening of condenser bypass valves.

- **Reactor Coolant Flow Increase**

These transients include events that might increase the recirculation flow and thus induce a positive reactivity increment. They include a malfunction of the recirculation flow controller in a manner to cause increasing primary coolant flow and the start-up of a recirculation pump that had been on standby.

- **Reactor Water Temperature Decrease**

These transients include events that might cause a power surge by reduction of the reactor primary coolant water temperature. They include malfunction of feedwater control in a direction to increase feedwater flow, loss of a feedwater heater, shutdown cooling malfunction, and inadvertent activation of auxiliary cold water systems.

- **Reactivity Insertions**

These transients include control rod withdrawal transients from the zero reactor power, hot, critical condition and from full power; fuel assembly insertion; control rod removal; and control curtain removal errors during refueling.

- **Reactor Coolant Flow Decrease**

These transients include failure of one or more recirculation pumps or malfunction of the recirculation flow control in a direction to cause decreasing flow.

The transients having the greatest potential for significant damage are those leading to a reactor primary coolant system pressure increase. The most severe of these are the loss of condenser vacuum and the closure of all main steam isolation valves. A loss of condenser vacuum causes automatic closure of the turbine stop valves and the turbine bypass valves. The turbine stop valves are fast acting valves, so that there is an abrupt interruption of steam flow from the reactor. The main steam isolation valves are slower in closing, but in this case the large steam line volume is not available to buffer the pressure rise. The result in either case would be an increase in primary system pressure and temperature. The pressure increase would decrease the volume of steam bubbles in the reactor core and this, in turn, would increase the reactivity and cause a surge in reactor power. The power surge would cause a further increase in system temperature and pressure, with the pressure rising to values above acceptable limits. The other transients that lead to primary system pressure increase are less severe. Generator or turbine trips are less severe because the turbine bypass valves can be assumed to open and the condenser to be operative. Although the transient proceeds more slowly in these cases, the result still would be an excessively high reactor coolant system pressure.

1971

The ACRS and the regulatory staff concluded that a design change to the proposed Newbold Island (now Hope Creek) BWR/4 (Public Service of New Jersey) was appropriate to limit the possible consequences of ATWS. The same design change was applied to other BWR/4s. The design change consisted of tripping of the recirculation pumps.

1972

The ACRS recognizes ATWS as a low probability event. Nevertheless, it believed that, in consideration of the large number of BWRs expected eventually to be in operation, and in view of the expected occurrence rate of anticipated transients, experience with scram systems of current design is insufficient to give assurance of an adequately low probability for an ATWS event with possible serious consequences. Accordingly a set of positions and actions is implemented and was published as WASH-1270.

1973

The regulatory staff amends licensing position setting October 1, 1973 as the effective date of the position. Analyses for older operating plants should be provided by October 1, 1974, and the need for any changes would be considered on a case-by-case basis. Plants recently started in operation, now under construction, or for which applications for construction permits are filed before October 1, 1976, should have any equipment provided and any changes made that are necessary to make the consequences of ATWS acceptable. Analyses of the effects of ATWS and plans and schedules for any changes found necessary should be provided for these plants by October 1, 1974, or at the time of submission of an application for a construction permit, whichever is later. Plants for which applications for construction permits are filed after October 1, 1976, should have improvements in the protection system design that make an ATWS event negligibly small.

Applicants should be required to:

- demonstrate that with their present designs the consequences of anticipated transients without scram (ATWS) are acceptable,
- or make design changes which render the consequences of anticipated transients without scram acceptable,
- or make design changes to improve significantly the reliability of the scram system.

It is necessary to establish acceptable consequences of ATWS in order to implement either option 1 or option 2 of the recommended position. Acceptable conditions are defined as follows:

- **Radiological Consequences**

The radiological consequences shall be within the guideline values set forth in 10 CFR Part 100.

- **Primary System Pressure**

The maximum acceptable transient primary system pressure shall be based on the primary system pressure boundary limit or the fuel element limit whichever is more restrictive. Primary pressure boundary limits transient pressure shall be limited to less than that resulting in a maximum stress anywhere in the reactor coolant pressure boundary of the "emergency conditions" as defined in the ASME Section II Nuclear Power Plant Components Code.

Fuel pressure limits transient pressure shall not exceed a value for which test and/or analysis demonstrate that there is no substantial safety problem with the fuel.

- **Fuel Thermal and Hydraulic Effects**

The increase in fuel enthalpy shall not result in significant cladding degradation or in significant melting of fuel even in the hottest fuel zones.

- **Containment Conditions**

Calculated containment pressures shall not exceed the design pressure of the containment structure. Equipment which is located within the containment and which is relied upon to mitigate the consequences of ATWS shall be qualified by testing in the combined pressure, temperature and humidity environment conservatively predicted to occur during the course of the event.

- **Analyses of Possible Detrimental Effects of Required Modifications**

Any modifications made to comply with option 2 of the recommended position shall be shown not to result in violations of safety criteria for steady state, transient, or accident conditions and shall not substantially affect the operation of safety related systems.

- **Diversity Requirement for Implementing Option 2 of the Recommended Position**

Design changes to make the consequences of ATWS acceptable should not rely on equipment or system designs which have a failure mode common with the scram system. The equipment involved in the design change shall, to the extent practical, operate on a different principle from equipment in the scram system. As an absolute minimum, the equipment relied on to render acceptable the consequences of the ATWS event shall not include equipment identical to equipment in the associated scram system.

- **Diversity Requirement for Implementing Option 3 of the Recommended Position**

Improvements must reduce considerably the potential for common mode failure of the scram system. Failures of identical equipment from a common mode should not disable sensing circuits, logic, actuator circuits or control rods to the extent that scram is ineffective. The addition of a separate protection system utilizing principles diverse from the primary protection system is indicated in order to meet this requirement.

1974

Reactor vendors submitted analyses on ATWS in general response to the following requirements set forth in WASH-1270:

- Trip of the reactor recirculation pump upon high reactor vessel pressure or low low reactor water level.
- Logic for automatic initiation of the liquid control system.
- Add piping to supply some of the liquid control flow through the HPCI system.

1975

ATWS is almost resolved. With the issuance of WASH-1400 (Assessment of Accident Risks), reactor vendors turned to the results which demonstrated that ATWS was not a major contributor to the risk from LWRs and as such no modifications are required.

1976

ATWS remained a controversial issue between the NRC and the industry.

1977

NRC formed a task force on ATWS in an effort to finally resolve the matter. The report sent to ACRS, reiterated the general position of scram unreliability which could not be shown to be acceptable low and measures were required to mitigate the consequences of ATWS. The year 1977 passed without issuance of a new NRC position on ATWS.

1978

The NRC issues NUREG-0460 (Anticipated Transients Without Scram for Light Water Reactors). The NUREG includes the Following:

- **ATWS Acceptance Criteria**

The staff recommends that all nuclear power plant designs should incorporate the designs features necessary to assure that the consequences of ATWSs would be acceptable. The primary criterion for acceptability is that the calculated radiological consequences must be within the dose guidelines values set forth in 10 CFR Part 100. In addition, more specific acceptance criteria have been developed for primary system integrity, fuel integrity, containment integrity, long-term shutdown and cooling capability, and the design of mitigating systems.

- **Containment Integrity**

The calculated containment pressure, temperature and other variables shall not exceed the design values of the containment structure, components and contained equipment, systems or components necessary for safe shutdown. For boiling water reactor pressure suppression containments, the region of relief or safety valve discharge line flow rates and suppression pool water temperatures where steam quenching instability could result in destructive vibrations shall be avoided.

- **Long-Term Shutdown and Cooling Capability**

The plant shall be shown to be capable of returning to a safe cold shutdown condition subsequent to experiencing an ATWS event, i.e., it must be shown that the reactor can be brought to a subcritical state without dependence on control rod insertion and can be cooled down and maintained in a cold shutdown condition indefinitely.

- **Fuel Integrity**

Damage to the reactor fuel rods as a consequence of an ATWS event shall not significantly distort the core, impede core cooling and prevent safe shutdown. The number of rods which would be expected to have ruptured cladding shall be determined for the purpose of evaluating radioactive releases.

- **Primary System Integrity**

The calculated reactor coolant system pressure and temperature shall be limited such that the calculated maximum primary stress anywhere in the system boundary, except steam generator tubes, is less than that permitted by the "Level C Service Limit" as defined in Section III of the ASME Nuclear Power Plant Components Code.

In addition, the deformation of reactor coolant pressure boundary components shall be limited such that the reactor can be safely brought to cold shutdown without violating any other ATWS acceptance criterion. the integrity of steam generator tubes may be evaluated based on a conservative assessment of tests and the likely condition of the tubes over their design life.

- **Mitigating Systems Design**

Mitigating systems are those systems, including any systems, equipment, or components, normally used for other functions, relied upon to limit the consequences of anticipated transients postulated to occur without scram. These systems shall be automatically initiated when the conditions monitored reach predetermined levels and continue to perform their function without operator action unless it can be demonstrated that an operator would reasonably be expected to take correct and timely action. These systems shall have high availability and in combination with the reactor protection system shall provide two independent, separate and diverse reactivity shutdown functions. The mitigating systems shall be independent, separate and diverse from the reactor trip and control rod systems, including the drive mechanisms and the neutron absorber sections. The mitigating systems shall be designed, qualified, monitored and periodically tested to assure continuing functional capability under the conditions accompanying ATWS events including natural phenomena such as earthquakes, storms including tornadoes and hurricanes, and floods expected to occur during the design life of the plant.

1979

The TMI accident forced deferral of all NRC work on ATWS and most industry work was halted or delayed as well.

1981

Proposed rules filed in federal register Vol. 46,. No. 226:

Rule #1
Early Operating Reactors

a. Modify the control rod drive scram discharge volume.

b. Provide actuation circuitry that is separate from the reactor protection system (i.e., recirculation pump trip)

Operating Plants With Construction Permits Issued Prior to 1/1/78

Provide automatic initiation of the Standby Liquid Control system and increase its flow capacity.

New Plants and Plants With Construction Permits Issued on or After 1/1/78

Addition of high capacity neutron poison injection systems.

Rule #2
Proposed Hendrie Rule

The essence of the Hendrie rule is that power reactor licensees would be required to implement a reliable assurance program to seek out and rectify reliability deficiencies in those functions and systems that prevent or mitigate ATWS accidents.

Bases for ATWS Rules

In large, modern boiling water reactors, a transient with failure to scram from full power is very likely to cause or may follow the isolation of the reactor (i.e., turbine trip or main steam isolation valve closure). If the recirculation pumps continue to run, the power level will remain high and a severe pressure excursion will take place. Even if the reactor coolant system survives the pressure surge, the very high steam flow will rapidly heat the suppression pool and pressurize the containment. In addition, the High Pressure coolant Injection (HPCI) System may not suffice to cool the core: overheating and core damage may follow. Ultimately the containment is expected to rupture due to over pressure while the core sustains damage. Continued core coolant replenishment is questionable after containment rupture. A large radiological release is a plausible outcome. A necessary mitigating feature is thus a prompt automatic trip of the recirculation pumps to avoid the pressure excursion and diminish the power and the consequent steam flow to the suppression pool. Given a trip of the recirculation pumps, the reactor power will stabilize at roughly 30% power until the reactor coolant boils down and steam bubbles (void formation) in the core throttle the chain reaction. Thereafter, a oscillatory equilibrium will be maintained in which the reactor sustains the average power necessary to boil off however much reactor coolant is delivered up to about 30% power. Analysis shows that HPCI or main feedwater can adequately cool the core to avoid extensive core damage. However, the power delivered to the suppression pool will be greater than the pool cooling system can dissipate. Therefore, containment over pressure failure remains a distinct possibility unless the reactor is shutdown, either by control rod insertion or by liquid reactivity poison injection. Well before the containment is significantly pressurized, the suppression pool will approach saturation and steam condensing will become unstable. Chugging steam condensing may threaten containment integrity or pressure suppression and thus shorten the time available to shutdown the reactor without unacceptable consequences. The HPCI is a single-train system.

The fault or human error that precipitates the initial transient might also disable the HPCI. In addition, system reliability analyses have indicated that HPCI may fail or be unavailable in as many as from 1% to 10% of the cases in which a demand is made of the system. This may be insufficient reliability for the mitigation of a potentially serious accident having a frequency of occurrence that might be as high as once in a thousand reactor years. A second diverse system, the Reactor Core Isolation Cooling (RCIC) System should be expected to auto start and run, delivering coolant to the reactor. If RCIC is the sole operative means of replenishing reactor coolant, the adequacy of core cooling, rather than the heat deposited in the suppression pool, is likely to be the factor limiting the time allowed to shut down the reactor without unacceptable consequences. The RCIC can successfully cool the reactor once it is shut down, and it can slow the boil off of reactor coolant in the reactor.

The NRC has concluded that the liquid reactivity poison injection system in large modern BWRs must have a start time and poison injection rate such that either of two redundant trains of high pressure reactor coolant replenishment systems, either of which may be expected to be available under ATWS conditions, can successfully mitigate ATWS transients. The two trains may be the HPCI and RCIC.

Concern has been expressed that the RCIC, though capable of meeting these success criteria, does not prevent the automatic depressurization of the reactor coolant system. Operator action is necessary in less than ten minutes to override the automatic depressurization. The NRC staff does not wish to force an alteration of the logic governing the Automatic Depressurization system (ADS) which might compromise the reliability of the ADS in non-ATWS events.

Several factors complicate the analysis of the ATWS tolerance of BWR plants. The delivery of main feedwater which may be available in some ATWS accident sequences may dilute liquid poison and increase the power level in ATWS events, thus threatening successful mitigation. In some sequence variants, operators might be tempted to depressurize the reactor to enable low pressure reactor coolant injection but, in so doing, disable turbine-driven coolant injection systems or otherwise compromise possible avenues of successful ATWS mitigation.

10CFR 50.62 (3) (4)

The Code of Federal Regulations requires all BWRs to have an alternate rod injection (ARI) system that is diverse (from the reactor trip system) from sensor output to the final actuation device. The ARI must have redundant scram air header exhaust valves. The ARI must be designed to perform its function in a reliable manner and be independent (from the existing reactor trip system) from sensor output to the final actuation device.

Each BWR must have a standby liquid control system (SLC) with the capability of injection into the reactor vessel of a borated water solution at such a flow rate, level of boron concentration and boron-10 isotope enrichment, and accounting for reactor pressure vessel volume, that the resulting reactivity control is at least equivalent to that resulting from the injection of 86 gallons per minute of 13 weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor vessel for a given core design. The SLC system and its injection location must be designed to perform its function in a reliable manner. The SLC initiation must be automatic for plants granted a construction permit prior to July 26, 1984, and for plants granted a construction permit prior to July 26, 1984, that have already been designed and built to include this feature.

Each BWR must have equipment to trip the recirculation pumps automatically under conditions indicative of an ATWS.

Design Requirements
ARI
SLC
ATWS-RPT

PRA Insight

The NRC staff evaluation of ATWS in NUREG-0460 was one of the first applications of PRA techniques to an Unresolved Safety Issue (USI). The evaluation highlighted the relative frequency of severe ATWS events for various reactor types and estimated the expected reduction in frequency for various postulated plant modifications. The study also proposed quantitative goals for resolving this issue. Other notable examples of PRA applications to the ATWS issue are the NRC sponsored survey and critique of reactor protection system (SAI,1982), and the ATWS Task Force report summarized in SECY-83-293. The RPS survey reviewed 16 reliability studies, most of them published PRAs, to compare the predicted failure probability per unit demand, the anticipated transient frequency, and the primary influences on RPS unavailability. There was a surprising degree of agreement among the 16 studies. The second study quantified the relative improvement to be gained by implementing a set of recommendations proposed by the utility consortium in an ATWS petition to the NRC. The third study, a value impact evaluation of the risk reduction of generic plant classes, provided the basis for a final rule on ATWS (SECY-83-293).

NUREG-1150 looked at several accident sequences which include a failure of the reactor protection system. One of the major sequences is initiated by a transient that requires a reactor scram. The mechanical RPS fails which eliminates any possibility of scramming the reactor or manually inserting control rods. The recirculation pumps are tripped and the SRVs properly cycle to control reactor pressure. The standby liquid control system is initiated manually to inject borated water into the reactor to reduce reactivity. The ADS valves are not inhibited and the reactor depressurizes which allows low pressure cooling systems to operate. The RHR system is placed in the suppression pool cooling mode or containment spray mode for containment overpressure protection, resulting in a safe core and containment.

An ATWS does have the possibility of leading to a core damage situation if the operator does not follow the Emergency Operating Procedures and initiate corrective actions like SLC initiation. However, the total contribution to the core damage frequency may not be very large (31% at Peach Bottom to 6% at Fermi).

Question:
Ask the class to provide 3 scram signals from the MSIV closure event.
- MSIV closure <90% open
- High reactor pressure
- APRM high power

MSIV closure event, no operator action.

NOTE:
For the calculations reported in the tables and figures, the assumption is made that none of the control rods move into the core. The calculation period starts 50 seconds after the valves close and ends with the overpressure failure of the drywell about 37 minutes later. Prior to the 50 second mark, power had already peaked at 527% and then reduced by ATWS-RPT.

Figure 4.2-1

Explain the reactor vessel instruments used under normal and emergency conditions. Indicate which are calibrated hot (cold).

Table 4.2-1 and Figure 4.2-2

50 seconds
- power decreases due to the decrease in water level
- water level 500 inches and decreasing rapidly
- reactor pressure about 1100 psig.
- Pressure cycling between 1100 and 1000 psig in response to SRV actuation
- HPCI and RCIC start
  - 5,000 gpm HPCI
  - 600 gpm RCIC

The water level increases slightly when HPCI and RCIC begin to inject and the core thermal power changes correspondingly until the total vessel injection (HPCI, RCIC, CRD) is equivalent to the steam production rate. After reaching this quasi-equilibrium state, the water level fluctuates about a mean of 476 inches in response to vessel pressure changes. The magnitude of the pressure peaks and valleys is attributed to the number of SRVs per group that lift.

All the steam produced that is not used by HPCI and RCIC is discharged by the SRVs to the suppression pool.

1 minute to 14.8 minutes

During the first 15 minutes of the accident sequence the suppression pool temperature increases from 90 degrees to 190 degrees fahrenheit with 100% condensation effectiveness.

Water level in suppression pool increases about one foot.

Why does the HPCI suction transfer to the suppression pool?

HPCI automatically shifts to suppression pool suction at +7 inches. This ensures sufficient free air space for the accumulation of non condensibles following a LOCA.

The increasing pool temperature challenges the ability of the HPCI to keep running.

TVA/FSAR Amendment 67 (page 14.1-14.5)

The HPCI system can, for a limited time, pump water temperature of 162 degrees without failure. Oil temperatures in excess of 200 degrees are to be avoided.

Between the times of 8.3 minutes and 14.8 minutes, the suppression pool temperature reaches 190 degrees. HPCi fails and ends the initial phase of the accident sequence by reducing the injection rate to just RCIC and CRD.

HPCI trip

Point out the effect water level has on core power when HPCI trips.

When the HPCI system trips, a mismatch between the pounds mass of steam leaving the vessel and the pounds mass of water entering the vessel is realized.

The downcomer water level decreases rapidly and is below 413 inches within 1.3 minutes.
- As water level decreases, the natural core circulation decreases, introducing additional negative void reactivity to reduce power to 4%.
- At 413 .5 inches the LPCI and CS pumps start, and the ADS timer is energized.

ADS actuation

Actuation immediately opens six (6) SRVs
- Rapid loss of water inventory uncovers the core within one minute
- With the core uncovered, criticality cannot be sustained and core thermal power subsides to decay heat level. (Heatup is slow with no immediate fuel damage)

The CBPs begin injecting followed by the CS and LPCI pumps.
- Combined flow is about 67,000 gpm and recovers core in 20 seconds.
- Vessel pressure is still to high for designed flows

The continued increase in water level sets the stage for a power excursion to 5%.
- At a low reactor pressure of 113 psig, 6 SRVs are not sufficient to remove the energy from increased steam production.
- Pressure and core power increase together, with the increase in one stimulating the increase in the other.
  - All SRVs open limiting presure tojust over 1100 psig.
  - Core thermal power increases to 178%

Figure 4.2-3

Drywell temperature 200 °F

During the first 21 minutes of the accident sequence, the bulk temperature of the suppression pool increases from 122 °F subcooled to 10 °F subcooled. (100% of SRV discharge condensed)

Drywell pressure increases about 3 psi during this time from the surface of the suppression pool steaming.

After 21 minutes the suppression pool no longer has the 10 °F subcooling required for 100% condensation of SRV discharge.
- A fraction, 10 to 20%, is allowed to bubble up and break through the surface into the wetwell atmosphere.
- Steam quickly enters the drywell atmosphere via 12 - 2 foot diameter vacuum breakers.

Drywell Failure

About 1.5 minutes before failure, pressure exceeds 110 psia and the ADS valves close.
- The valves require >5 psi air pressure to operate (115 psi air pressure - 110 psi atmosphere = 5 psi)

At 37 minutes, the drywell pressure reaches the assumed 132 psia failure pressure.

Reason for no operator action discussion.

The purpose of the no operator action discussion is to provide information concerning what the specific goals of operator action should be. The most important response was the early failure of the HPCI system which caused actuation of ADS. Actuation of the ADS allowed the injection of all low pressure ECCS pumps and condensate booster pumps.

Ask the class for any other failures/problems that challenge structure, systems, or components.

In addition to the drywell failure, the oscillation of reactor pressure could cause failure of the low pressure ECCS injection piping which could lead to an interfacing system LOCA.

To forestall the failure of containment the rate of steam discharge to the suppression pool needs to be reduced.
- Reduce reactor power
- Prevent pressure spikes

Ways to reduce reactor power ====>>>	**Insertion of control rods** **• Scram manually** **• RMCS (normal rod movement)** **Initiation of SLC** **Water level control** **Pressure control**
Normal response of CRD and RPS system with scram signal ====>>>	• Scram solenoid valves for each HCU deenergize • Backup scram solenoid valves energize • Air is vented from the scram inlet and outlet valves permitting the valves to open with spring pressure. • Air is vented from the SDV vent and drain valves permitting them to close. • FCV closes due to flow rate being greater than desired.
Operator initiated manual scram.=======>>>>>	• Mode switch - out of run (APRM 15%) - Shutdown position • Scram buttons • Vent the scram air header • Pull fuses to RPS **NOTE:** **If the scram failure was due to hydraulic lock, all scram signals must be cleared before the SDV can be drained to allow a manual scram.**
Rod insertion via the RMCS	• With a scram signal present, the operator must open the FCV manually. In addition to the FCV, the operator should also close the drive water pressure control valve to obtain maximum differential pressure. • eliminate the settle function by using the emergency insert switch - Assuming a rod speed of 3 in/sec (48 seconds total), about 2.5 hours required to insert all rods at end of core life. Time to hot shutdown about 20 minutes if the correct 25 rods are inserted.
Initiation of SLC	The initiation of SLC is manual via a key locked switch. Complete dispersal of the poison into the core is not expected to occur unless there is sufficient turbulent core flow to enhance the mixing of core inlet plenum water and SLC. The high specific gravity of poison (1.1), prevents a uniform dispersal of the injected poison upward into the core region unless there is a core inlet flow sufficient to induce turbulent flow in the reactor vessel lower plenum.

To complete this goal, the operator would not increase water level until sufficient poison has been injected (25 min). Water level is lowered to reduce power and provide a more efficient heat transfer between HPCI & RCIC water with steam in the downcomer annulus area (more BTU/lbm).

4.3 POWER OSCILLATIONS

Learning Objectives

Learning Objectives

1. List the primary safety concern regarding unstable power oscillation.
2. List the major factors that can contribute to instability.
3. Explain the mechanism present at most BWR plants to guard against neutron flux oscillations.
4. Define the following terms:
   a. fuel time constant
   b. decay ratio
5. Explain why it is difficult to detect power oscillations.

4.3.1 Introduction

Common types of oscillations

Boiling water reactors (BWRs) have complex dynamic responses that can result in the initiation of power oscillations. Of the various types of oscillations, those generated from control systems response are the most common. Controllers, such as the master recirculation flow controller, are typically more stable at the high end of their control band than at the low end. To account for this problem, interlocks and procedures prevent automatic master flow control below some value (typically less than 45%). Other control systems that effect BWR oscillations are the pressure control system and the feedwater control system. Even with the constant modulation of the turbine control valves to regulate reactor pressure and feedwater pump steam supply valves or feedwater regulating valves to control feedwater flow, a sinusoidal oscillation can be observed in reactor power during steady state operation. These oscillations are usually slow and small in magnitude. Figure 4.3-1 was taken from an operating recorder in a BWR control room and illustrates the power oscillations that occur at many plants during normal power operation. The amplitude of these observed oscillations has ranged from a few percent to fifteen percent. Oscillations that occur from control system responses are not normally divergent and do not challenge fuel safety limits.

Figure 4.3-1

Objective #1

Unstable power oscillations can occur during power operations or in conjunction with an Anticipated Transient Without Scram (ATWS). The primary safety concern regarding unstable power oscillations during normal operations is the ability of the reactor protection system to detect and suppress oscillations before they can challenge the fuel safety limits

(Minimum Critical Power Ratio).

Objective #2

Objective #3

T/S page 3.4-4, Figure 3.4.1-1

Objective #4b
bases B.3.4-2

The type of instability that can lead to divergent oscillations and challenge fuel safety limits is a thermal-hydraulic, neutronic generated, density-wave instability that occurs inside fuel bundles. GE BWR plant and fuel design provide stable operation with margin within the normal operating domain. However, at the high power/low flow corner of the power/flow operating map, the possibility of power oscillations exists. **The major factors that can contribute to instability are void fraction, fuel time constant, power level, power shape, feedwater temperature and core flow.** To provide assurance that the oscillations are detected and suppressed, **technical specifications require that APRM and LPRM flux levels be monitored when in the region of possible power oscillation.** This requirement is based on the results of stability tests at operating BWRs. A conservative decay ratio of 0.6 was chosen as the basis for determining the generic region for monitoring for power oscillation. **Decay ratio in this context is the measured stability of an oscillating system and is the quotient of the amplitude of one peak in an oscillation divided by the amplitude of the peak immediately preceding it.** The amplitude is measured relative to the average amplitude of the signal. A stable system is characterized by a decay ratio of less than 1.0. As a result of recent power oscillation events, and a desire to minimize the possibility of exceeding the minimum critical power ratio (MCPR) limit, the BWR Owners Group (BWROG) and the NRC have agreed in principle to three plausible options that are discussed in Section 4.3.3 on Mitigation of Power Instability.

Thermal-hydraulic-neutronic instabilities in BWRs have been known to exist since the early days of BWR research using prototype reactors. Although this instability mechanism was identified early, the analysis methods needed to predict its effect are only now becoming available. Appendix 1, Analysis Methods Used For BWR Stability Calculations, is, therefore, provided for additional information.

4.3.4 Historical Perspective

Evaluation of the probability of thermal-hydraulic instability in BWRs has been an ongoing study by General Electric starting with the first power production plants. Early testing consisted of moving a control rod one notch position while monitoring reactor performance. For BWR/3s, 4s, 5s, and 6s with high power density cores, a pressure disturbance technique was used to cause power instability. The pressure disturbance was accomplished using one of the four turbine control

Caorso test 1982 180 degrees out of phase. Power Density 55kw/l

valves. The signal used to control the perturbation amplitude was adjusted to obtain an APRM neutron oscillation within 15% of the steady state signal.

Tests following the instability scrams (one each in 1982 and 1983) at the Caorso Nuclear Power Station (Italian plant), indicated the possibility of power oscillation at high power and low flow conditions. These tests also indicated an out-of-phase neutron flux oscillation and showed that half of the core was oscillating 180 out of phase with respect to the flux oscillation in the other half of the core (as sensed by the LPRMs). These tests also showed that APRMs would not be as sensitive to such a phenomenon. While the LPRMs indicated oscillations of 60% of peak-to-peak power, APRMs indicated oscillations of only 12%.

(SIL) 380, Revision 1 February 10, 1984

On February 10, 1984, General Electric issued Service Information Letter (SIL) 380, Revision 1, which discussed the BWR core thermal-hydraulic stability problems that could exist in different variations in all BWRs. The SIL **provided a list of recommended actions and identified the high power, low flow corner of the power-to-flow map as the region of least stability and one which should be avoided.** If this region of instability was entered, guidance was to insert control rods to reduce reactor power below the 80 percent rod pattern line and monitor LPRMs and APRMs for oscillation.

January 1986

1. Conform with SIL 380
2. Change T/S
3. Information about GDC 10 and 12

Generic Letter 86-02 was issued January 1986 to inform licensees of the acceptance criteria for thermal-hydraulic stability margin required in GDC 10 and GDC 12. The objective of the letter was to account for these criteria in future licensing submittals and in safety evaluations in support of 10 CFR 50.59 determinations. It also stated that plants may have to change technical specifications to comply with SIL 380, Rev. 1.

On March 9, 1988 the Unit 2 reactor at the LaSalle Station was operating at 84% steady state power and 76% flow when an instrument technician made a valve lineup error that caused both recirculation pumps to trip. As a result of the rapid power decrease, the EHC system reduced steam flow to the main turbine causing a reduction of extraction steam. The rapid decrease in extraction steam caused severe perturbations in feedwater heater levels which eventually caused isolation of the heater strings. Feedwater temperature decreased 45 F in 4 minutes as a result of this significant reduction in feedwater heating, causing an increased power-to-flow ratio and further reducing the margin to instability. Between 4 and 5 minutes into the event, the APRMs were observed to be oscillating between 25 and 50% power every 2 to 3 seconds accompanied by oscillating LPRM up scale and down scale alarms. The

Flow biased scram did not scram them, why?

December 30, 1988 NRC Bulletin 88-07, Supplement 1

unit automatically scrammed at the 7 minute mark from a fixed APRM scram signal of 118%.

On December 30, 1988 NRC Bulletin 88-07, Supplement 1, dealing with power oscillations in BWRs was issued. The purpose of this supplement was to **provide additional information concerning power oscillations in BWRs and to request that licensees take actions to ensure that the safety limit for minimum critical power ratio (MCPR) was not exceeded.** In addition, within 30 days of receipt of Supplement 1, all BWRs were required to implement the GE interim stability recommendations derived for GE fuel. **The supplement also specified that plants with ineffective automatic scram protection shall manually scram the reactor if both recirculation pumps should trip.** Adequate automatic scram protection is available at plants with a flow biased APRM scram with no time delay. **Inadequate automatic scram protection is provided at plants with a fixed APRM high flux scram and a separate thermal APRM, time delayed, flow-biased scram.**

1989 Sweden Plant

During the startup of cycle 13, of the Ringhals-l plant in Sweden in 1989, an unexpected out of-phase oscillation occurred with a peak-to-peak amplitude of about 16 percent. The event was initiated when high neutron flux power level triggered an automatic pump run back from 79 percent power to 68 percent power. An analysis following the event appeared to indicate that the slope of the flow control line was altered by the new fuel cycle and that an increase in recirculation flow resulted in greater-than-expected increases in power.

1991 Caorso

The **Caorso** nuclear power station (a BWR/6 located in Italy) experienced an unexpected instability event in 1991. The event occurred during a reactor startup, using GE-7 fuel, and with plant conditions of minimum pump speed, minimum flow control valve position, and a rod pattern line of nearly 80 percent. Actual power and flow values were uncertain but were estimated to be in the range from 38 to 40.8 percent power and from 30.7 to 31.3 percent flow. This event demonstrated that oscillations below the 80 percent rod line are possible and suggested that the regions defined in NRC Bulletin 88-07 may not have been restrictive enough. This event occurred during a startup and was attributed to extreme bottom-peaking of the axial power shape. The feedwater heaters were still cold when the event occurred with a feedwater temperature of approximately 150oF and 56 BTU/lb of subcooling. **An interesting effect occurred during the event. The power oscillations continued to grow in amplitude while core power was clearly decreasing as the operator inserted the control rods.** The corrective action to avoid repetition of this event was to modify the plant startup procedures to

August 15, 1992,

W N P Unit-2

require a hot feedwater temperature before power could be increased above 30 percent power.

On August 15, 1992, Washington Nuclear Power Unit-2 experienced power oscillations during startup. The reactor core for cycle 8 consisted of mostly Siemens fuel (9*9-9x) that has a higher flow resistance than the GE 8*8 fuel. While on the **76% rod line** following a power reduction with flow, a power oscillation was observed by the operators who then initiated a scram. An Augmented Inspection Team (AIT) found, by analyses using LAPUR code, that a major contributor was the core loading. The analyses indicated that a full core load of 9*9-9x fuel would be less stable than the old 8*8 fuel and that the mixed core was less stable than a fully loaded core of either type. This event indicated that the boundaries of the instability region defined in the BWROG interim corrective actions may not include all possible areas of instabilities.

Figure 4.3-2

4.3.2 Discussion of Power Instability

The basic mechanism causing flow and power instabilities in BWRs is the density wave. The effect of a density wave is illustrated in Figure 4.3-2. Coolant flows in the upward direction through the core and is guided by the channels that surround the matrix of fuel rods. Local voiding within a fuel bundle may be increased either by an increase in the power at a constant inlet flow, by a decrease in the inlet flow at constant power, or by an increase in feedwater temperature. This resulting localized concentration of voids will travel upward, forming a propagating density wave which produces a change in the localized pressure drop at each axial location as it travels upward. The effective time for the voids to move upward through the core is referred to as the density wave propagation time. In two-phase flow regimes, the localized pressure drop is very sensitive to the local void fraction, becoming very large at the outlet of the bundle where the void fraction is normally the greatest. Because of this a significant part of the pressure drop is delayed in time relative to the original flow perturbation.

Figure 4.3-3

If a **sine wave perturbation of the inlet flow** is used to illustrate this, Figure 4.3-3 is obtained. The localized axial pressure drops are also sinusoidal within the linear range; however, they are delayed in time with respect to the initial perturbation, the sine wave in this case. The total pressure drop across the bundle is the sum of the localized pressure drops. If the bundle outlet pressure drop (the most delayed with respect to the initial perturbation) is larger than the inlet pressure drop, then the total bundle pressure drop may be delayed by as much as 180 degrees with respect to the inlet flow perturbation and be of the opposite sign. This is the case in Figure 4.3-3, where an increase in inlet flow results in a decrease in the total bundle pressure drop. Bundle flow with this density wave propagation time behaves as if it has a "negative" friction loss term. This causes the bundle flow to be unstable, inlet flow perturbations to reinforce themselves (positive feedback), and oscillations grow at the same unstable frequency. **Bundle flow instability starts when the outlet (i.e., delayed) localized pressure drop equals the pressure drop at the inlet for a particular density wave propagation time.**

Power generation is a function of the reactivity feedback and, depends strongly on the core average void fraction. When a void fraction oscillation is established in a BWR, power oscillates according to the neutronic feedback and the core dynamics. Most important to this discussion are the void fraction response to changes in heat flux, including the inlet flow feedback via the recirculation loop, and the reactivity feedback dynamics.

Objective #4a
Fuel Time Constant

One important difference between the neutronic feedback dynamics and the flow feedback dynamics is the fuel time constant. **Before the power generated in the fuel can effect the moderator density, it must change the fuel temperature and transfer heat to the coolant.** The fuel in BWRs responds relatively slowly with a time constant between 6 and 10 seconds. The delay times for unstable density wave oscillation and void reactivity feedback are not the same. Differences in the delay times add additional phase delays and can cause the void feedback to reenforce the density wave oscillations (effectively positive feedback). Decreasing the time response of the fuel generally has a destabilizing effect. Smaller response times can be a problem even if only a small portion of the fuel has the decreased time response, as was the case in the WNP2 event, because the **most unstable bundles dominate the response.**

When conditions within a reactor are such that it could become unstable (eg: high power and low flow), any perturbation in the inlet conditions can start the unstable oscillations. A moment before the instability event starts, the reactor is in a relatively steady condition with some particular power and flow. Initially the reactor will behave linearly and the oscillations will grow exponentially. As the oscillation becomes larger, the nonlinearities in the system begin to grow in importance. These nonlinearities have the effect of increasing the negative power feedback in the reactor. **When a sufficiently large reactivity bias is reached an equilibrium is established, and a limit cycle oscillation remains.** The amplitude of the resulting limit cycle oscillation will depend on various parameters and can be many times greater than rated full power.

BWRs can experience unstable power oscillation either in a single bundle (localized) or core wide. In the case of core wide oscillations, the entire core can oscillate together or part of the core can be increasing in power while another part is decreasing in power (out of phase). The out of phase oscillation is important because it is more difficult to detect. BWRs monitor local power at various radial and axial locations with the use of Local Power Range Monitors (LPRMs). The LPRMs consist of up to 172 stationary in-core detectors which are arranged in radially located assemblies of four detectors each, separated at axial intervals of three feet. The LPRMs in turn provide information to the Average Power Range Monitoring (APRM) System. In general for the majority of plants, a set of individual LPRMs provide information to a single APRM channel. APRMs sample power both radially and axially in the core and therefore, may not indicate the worst case out-of-phase oscillation since the oscillation may be masked by the cancellation between out of phase LPRMs that provide signals to the same APRM channel.

Bottom-peaked power shapes are more unstable because they tend to increase the axially averaged void fraction. This causes void perturbation to start at a lower axial level, and produces a longer delay time for the density wave which will be more unstable. Radial power shape is important because the most unstable bundles tend to dominate the overall response. Lower void velocities result in longer delay times for the density wave which will be more unstable. Increasing the subcooling of the feedwater inlet flow has two effects. First, it will tend to increase the operating power (a destabilizing effect) and second, it raises the boiling boundary (a stabilizing effect). In most cases the total effect is destabilizing. The fuel isotopic composition has an indirect effect on the density reactivity coefficient with the effect depending on the burnup. Generally increased burnup causes the density reactive coefficient to become less negative, which will tend to destabilize the core.

Many of these effects can accrue as a result of a single cause. As an example, fuel burnup will change the fuel isotopic composition as well as the axial power shape. Additionally, changes in other parameters can effect these factors. Increasing reactor pressure will decrease the core average void fraction and stabilize the reactor. Increasing the core inlet restriction (flow orificing) will increase the single phase component of the pressure drop across the core which retards dynamic increases in the flow rate (a stabilizing effect). Therefore, the effects of all parameters must be taken into account when evaluating mitigation strategies.

4.3.3 Mitigation of Power Instability

General Design Criteria (GDC) 10, 12, and 20 of 10 CFR 50, Appendix. A, require that protection systems be designed to assure that specified acceptable fuel design limits are not exceeded as a result of power oscillations that are caused by thermal-hydraulic instabilities. Minimum Critical Power Ratio (MCPR) is the primary fuel design limit that is being protected during potential instabilities.

The BWROG submitted to the U.S. Nuclear Regulatory Commission Topical Report NEDO31960, "Long-Term Stability Solutions Licensing Methodology," (Reference 7) for staff review. Long-term solutions described in this report consist of conceptual designs for automatic protection systems developed by the BWROG with its contractor, the General Electric Company. The automatic protection systems are designed to either prevent stability related neutron flux oscillations or detect and suppress them if they occur. This report also described methodologies that have been developed to establish set points and demonstrate the adequacy of the protection systems to prevent violation of Minimum Critical Power Ratio limits in compliance with 10CFR50, Appendix A, GDC 10 and 12.

Because of the variety of plant types, and the need to accommodate differing operational philosophies, and owner-specific concerns, several alternative solutions are being pursued. For some BWR/2s, existing systems and plant features already provide sufficient detection and suppression of reactor instabilities. This capability is limited primarily to those plants having quadrant average power range monitors (APRMs), it is referred to as Option II, and has been agreed upon by BWROG and the NRC. However, for most of the BWRs, new or modified plant systems may be necessary. A summary of the three most promising BWR owner group long-term solutions is provided below.

4.3.3.1 Solution Description Option I-A

Regional Exclusion, Option I-A, assures compliance with GDC-12 by preventing the occurrence of instability. This is accomplished by preventing entry into a power/flow region where instability might occur. An example of an exclusion region (I) is shown in Figure 4.3-4 along with the restricted (II) and monitored (III) regions. Upon entry into the exclusion region, an Automatic-Safety-Feature (ASF) function will cause the region to be exited. The ASF may be a full scram or a selected rod insert (SRI). For plants choosing SRI as their primary ASF, a full scram automatic backup must take place if the exclusion region is not exited within a reasonable period of time (a few seconds).

For plants choosing to implement this option (full scram or SRI), the existing flow-biased scram cards will be replaced. The new microprocessor-based cards will provide three independent functions: (1) a scram signal (that will be processed by the existing flow-biased scram system) if the exclusion region is entered, and (2) an alarm (directed to an existing alarm panel) if the restricted region is entered, and (3) automatic monitoring (using the period-based algorithm of solution III) within the monitored region to detect instabilities should they occur.

Entry into the monitored region is unrestricted. This region only defines a region outside which the monitoring algorithm is not active. The main purpose is to avoid false alarms from the automated monitor when operating at very low powers during startup. Intentional entry into the restricted region is only permitted if certain stability controls are in place. These stability controls deal primarily with power distributions and may be implemented by monitoring a parameter defined as the boiling boundary. The purpose of these controls is to assure that plant conditions that are sensitive to stability are bounded by the assumptions of the exclusion region boundary analysis.

4.3.3.2 Solution Description Option I-D

Regional Exclusion with Flow-Biased APRM Neutron Flux Scram, Option I-D, assures that BWRs with tight fuel inlet orificing (less than 2.43 inches) and an unfiltered, flow-biased scram comply with GDC-12 by providing an administrative boundary for normal operations in the vicinity of the region where instability could be expected to occur. During normal operation, the boundary of the exclusion region is administratively controlled, and operation within the region is to be avoided. If an unexpected operational event results in entry into the exclusion region, action to exit the region must be taken immediately. Oscillations that do occur in this situation should be automatically detected and eliminated by the flow-biased APRM neutron flux scram. This scram is based on a comparison of the unfiltered APRM signal to a set point that varies as a function of core flow. When the unfiltered APRM neutron flux signal exceeds the flow-biased set point, a scram signal is generated. An example of the administratively controlled region and the instability region is shown in Figure 4.3-5.

Some plants, like Cooper Nuclear Station, utilize the 3D Monicore Solomon program to monitor and alert the control room operators if the instability region is approached and/or entered.

4.3.3.3 Solution Description Option III

Local Power Range Monitor (LPRM) based Oscillation Power Range Monitor (OPRM), Option III, is a microprocessor-based monitoring and protection system that detects a thermal hydraulic instability and initiates an alarm and ASF before safety limits are exceeded. The OPRM does not affect the design bases for the existing APRMs because it operates in parallel with and is independent of the installed APRM channels.

The algorithms proposed for use in the automatic detection solutions, I-D and III are: High-Low-High Algorithm, Growth Algorithm and Period-Based Algorithm. The High-Low-High Algorithm establishes a setpoint at some value above 100% power. In order to cause a scram the signal must pass through the setpoint with a positive slope followed by passing through the setpoint with a negative slope and then pass the setpoint a second time with a positive slope. When the setpoint is set well above the random fluctuations that occur in reactor operation, this algorithm will prevent scrams that would otherwise result from single spikes. The Growth Algorithm is designed to detect the presence of oscillations as they grow above the level of normal random noise. If the amplitude of an oscillation is greater than the previous oscillations amplitude by a predetermined amount, a scram signal will be generated. The Period-Based Algorithm is the most sensitive of the automatic detection solution algorithms. It detects the "periodicity" of the signal by maintaining statistical data of the intervals between consecutive peaks. When the "periodicity" is high, the reactor is considered to be approaching instability.

Although not part of the BWROG proposed long term solutions, several "Decay Ratio" monitor designs have been developed and used. These on-line monitors can show operators how close the plant is to being unstable and have the same general principles of operation. They use the random fluctuations in the neutron population (reactor noise) to determine the current reactor decay ratio at any given time. The algorithm that is used (determination of the effective decay ratio by using the automatic correlation of the signal) must be time averaged to reduce the fluctuation inherent in this method and to increase its accuracy. Although these are on-line systems, the signal from the monitors is delayed by the averaging time (usually about 2 minutes). The Advanced Neutron Noise Analysis (ANNA) system by Siemens is used at WNP-2. At the present, the monitor at WNP-2 is only used for startup operations. The NRC has granted WNP-2 permission, through a technical specification change, to operate in the old exclusion region C provided the decay ratio monitoring system (ANNA) is in operation. The system was not in use during the oscillation events that occurred at WNP-2. The CASMO system by ABB-Atom and the SIMON system by EuroSim are in use at some foreign BWRs. In Sweden, decay ratio monitors are used at all times since the plants operate in a load following mode and routinely drop flow very close to the exclusion region. Reports indicate that the use of these monitors has prevented many reactor scrams and oscillation events. However, due to their high sensitivity, false alarms are not unusual, and the monitors may indicate high decay ratios when stable conditions exist.

The General Electric supplied NUMAC OPRM System, like the one installed at Plant Hatch, consists of four redundant and separate OPRM channels. Each channel independently monitors for oscillation.

The OPRM system safety trip and oscillation alarms are enabled only when the total recirculation flow value is below 60% and the simulated thermal power is greater than 30%. An alarm is generated when the reactor power and flow conditions enter the region of operation where the OPRM trip is enabled.

Figure 4.3-9

All OPRM system signal processing for an OPRM channel is performed by one APRM instrument (Figure 4.3-9) For any particular OPRM instrument, the associated APRM and OPRM channels use the same set of LPRM detector data and the same total recirculation flow data as input. Manual bypass of an APRM channel also causes a bypass of the corresponding OPRM channel.

The OPRM system monitors the thermal-hydraulic instabilities by monitoring the LPRM detector signals since the pressure and flow perturbations which occur during these instabilities cause localized oscillation of the LPRM detector signals. The entire set of LPRM detector signals received by an OPRM channel are divided into "cells" corresponding to a series of local regions in the reactor core which are monitored by the LPRM detectors in those regions.

The high frequency components of the non-bypassed LPRM detector signals assigned to a particular cell are removed by filtering the signals through a low-pass filter. These filtered LPRM detector values are then mathematically averaged together to obtain the characteristic flux value for the cell. This average flux value is passed through another low-pass filter with a 6 second time constant in order to create a time-averaged value of the cell flux. In this manner the cell reference value is normalized to a steady-state value of 1 and is independent of the actual flux value which changes depending on the overall reactor power level.

The cell reference value is supplied to three separate algorithms which test for neutron flux oscillations. These algorithm are the period based algorithm, amplitude algorithm, and the growth rate based algorithm.

Figure 4.3-10

The output of the OPRM system (Figure 4.3-10) provides a pre-trip alarm signal based on any of the three algorithms, a safety trip signal based on any of the three algorithms, and the OPRM trip enable alarm signal. The safety trip signal is sent to the safety section of the channel 2/4 logic module. The others are sent to the non-safety section. An OPRM channel INOP signal is generated to alert the operator of any event which compromises the operability of the OPRM channel. OPRM system data is transmitted by the APRM instrument to the process computer via the RBM instrument fiber-optic cabling. The APRM instrument's local display and the associated operator display assembly show pertinent information regarding the operation of the OPRM channel.

4.3.5 Analysis Methods Used For BWR Stability Calculations

Predictive calculations of BWR stability are too complex to allow for simple calculations and require computer codes to simulate the dynamic behavior of the reactor core. The family of codes that has been used to represent and to predict the stability of commercial BWRs can be subdivided in two main categories: frequency-domain and time-domain codes. Among the frequency domain codes are LAPUR, NUFREQ, and FABLE. Time-domain codes are more widely used and include RAMONA-3B, TRAC-BF1, TRAC-G, RETRAN, EPA, SABRE, TRAB, TOSDYN-2, STANDY, and SPDA.

LAPUR was developed at the Oak Ridge National Laboratory (ORNL) for the NRC and is currently used by NRC, ORNL, and others. LAPUR's capabilities include both point kinetics and the first subcritical mode of the neutronics for out of phase oscillations. The thermalhydraulic part is modeled to consider up to seven flow channels with inlet flows coupled dynamically at the upper and lower plena to satisfy the pressure drop boundary condition imposed by the recirculation loop. LAPUR's main result is the open- and closed-loop reactivity-to-power transfer function from which a decay ratio is estimated. Its current version is LAPUR-5.

NUFREQ is a set of codes called NUFREQ-N, NUFREQ-NP, and NUFREQ-NPW that calculate reactor transfer functions for the fundamental oscillation mode The main difference between them is their ability to model pressure as an independent variable (NUFREQ-NP) so that the pressure perturbation tests can be reproduced. NUFREQ-NPW is a proprietary version currently used by Asea Brown Boveri (ABB); its main feature is an improved fuel model that allows modeling of mixed cores.

FABLE is a proprietary code used by General Electric (GE) which can model up to 24 radial thermal-hydraulic regions that are coupled to point kinetics to estimate the reactor transfer function for the fundamental mode of oscillation.

RAMONA is a code that was developed by ScandPower; it is currently used by Brookhaven National laboratory (BNL), ScandPower, and ABB. The RAMONA-3B version was developed by BNL and has a full three dimensional (3D) neutron kinetics model that is capable of coupling to the channel thermal-hydraulics in a one-to-one basis. Typically, when using time-domain codes, the thermal-hydraulic solution requires orders of magnitude more computational time than the neutronics codes. Because of the large expense associated with the computational time, thermal-hydraulic channels are often averaged into regions to reduce computational time. RAMONA-3B uses an integral momentum solution that significantly reduces the computational time and allows for the use of as many computational channels as necessary to accurately represent the core.

TRAC has two versions currently used in BWR stability analysis. TRAC-BF1 is the open version used mostly by Idaho National Engineering Laboratory (INEL) and Pennsylvania State University, while TRAC-G is a GE-proprietary version. TRAC-BF1 has one dimensional neutron kinetics capabilities (as well as point kinetics). TRAC-G has full 3D neutron kinetics capability (as well as one dimensional and point kinetics), and GE has incorporated most of its proprietary correlations. The numerics in TRAC-G have also been improved with respect to those in TRAC-BF1 to reduce the impact of numerical diffusion and integration errors. Typically TRAC runs are very expensive in computational time; to minimize this time, most runs are limited to the minimum number of thermal-hydraulic regions that will do the job (typically 20).

RETRAN is a time-domain transient code developed by the Electric Power Research Institute (EPRI). It has one dimensional and point kinetics capability and is a relatively fast-running code since it models a single, radial, thermal-hydraulic region and uses the so-called three equation approximation (i.e, it assumes equilibrium between phases). A big advantage of RETRAN over other more detailed tools is that it is capable of running in a desk-top personal computer environment.

Engineering Plant Analyzer (EPA) is a combination of software and hardware that allows for real time simulation of BWR conditions including most of the balance of plant. It was developed for NRC and is located at BNL. EPA's software for BWR stability simulations (named HIPA) models point kinetics with mainly an average thermal-hydraulic region; a hot channel is also modeled but does not provide significant feedback to affect the global results. HIPA uses modeling methods similar to those of RAMONA-3B and, in particular, it uses the integral momentum approach to speed up the thermal-hydraulic calculations. An interesting feature of HIPA is its ability to use time dependent axial power shapes to compute the reactivity feedback. The nodal power shape is varied according to the local void fraction as a function of time based on some polynomial fits that are input to HIPA.

SABRE is a time domain code developed and used by Pennsylvania Power and Light for transient analyses that include BWR instabilities. SABRE uses point kinetics for the neutronics and a single thermal-hydraulic region.

TRAB is a one dimensional neutronics code with an average thermal-hydraulic region. It was developed and used in the Finish Center for Radiation and Nuclear Safety and has been benchmarked against RAMONA-3B calculations and a stability event in the TVO-I plant.

TOSDYN-2 has been developed and used by Toshiba Corporation. It includes a 3D neutron kinetics model coupled to a five-equation, thermal-hydraulic model and models multiple parallel channels as well as the balance of plant.

STANDY is a time domain code used by Hitachi Ltd. It includes 3D neutron kinetics and parallel channel flow across at most 20 thermal-hydraulic regions. STANDY is a vessel model only and does not include the balance of plant.

SPDA, a combination of RELAP5 and EUREKA, is used by the Japan Institute of Nuclear Safety. RELAP5 calculates the thermal-hydraulic part of the solution, while the nodal power is estimated by EUREKA (which is a 3D neutron kinetics code).

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4.4 PRE-CONDITIONING INTERIM OPERATING MANAGEMENT RECOMMENDATION (PCIOMR)

Learning Objectives :

1. Describe pellet-clad interaction type fuel failure.
2. Explain the purpose of PCIOMR.
3. Describe the basic PCIOMR rules.
4. Define the following terms:
   - threshold
   - PC envelope
   - ramp rate

4.4.1 Introduction

During rapid power increases above previous operating levels, thermal expansion of the fuel pellets can produce Pellet Clad Interaction (PCI) that causes high localized stress in the cladding. When these stresses occur in the presence of fission products, the PCI may cause failure of the cladding. The defects generally appear as longitudinal tight cracks, and for power levels typical of 8x8 fuel designs, occur at exposures beyond 5000 MWd/t.

One of the measures taken to counteract the PCI failure in operating BWRs was a procedure for limiting the number and types of sudden power increases that produce levels above previous operating values. This procedure is called the Preconditioning Interim Operating Management Recommendation (PCIOMR).

The PCIOMR is based on results of plant surveillance, fuel inspections, and individual fuel rod testing in the General Electric Test Reactor (GETR). Tests at GETR in 1971 and 1972 confirmed the mechanism and characteristics of the PCI failures observed in operating BWRs during rapid power increases. Beginning in late 1972 and early 1973 a series of tests in GETR using early production fuel rods demonstrated that a slow ascent to power would not only prevent fuel failure, but that the slow ramp "preconditioned" the fuel to withstand subsequent rapid power changes at all levels up to that attained during the initial slow power increase (PC envelope). These tests served as the bases for the PCIOMR that was introduced in mid-1973.

Subsequent testing, and as surveillance of operating reactor experience, has allowed some modifications to the original procedures. These modifications include more flexibility at low exposures through use of a higher power level (often referred to as the threshold power) for initiation of the preconditioning ramp, by use of maintenance procedure which allows retention of preconditioning for extended exposures. In 1978 a faster preconditioning ramp rate was introduced as a result of testing and analysis of GETR and operating data.

Since its introduction, the PCIOMR has been successfully implemented in operating BWRs throughout the world. The procedure has demonstrated its effectiveness in generally reducing the incidence of PCI failures on the earlier 7x7 fuel designs. In addition, the performance of newer fuel designs has been excellent when the PCIOMR is utilized. Not only has it been proven technically effective, but modifications to the procedure, and introduction of implementation aids and guides have made the PCIOMR a viable means for mitigating the effects of pellet-clad interaction.

4.4.2 Pellet Cladding Interaction

Pellet-clad interaction (PCI) failure of zircaloy clad fuel can occur during rapid power increases in irradiated fuel. Reactor operation produces fuel cracking and radial relocation of pellet fragments and also increases concentrations of fission products such as iodine and cadmium. The differential pellet-clad thermal expansion that occurs during a power increase may then cause pellet-clad interaction with high localized stresses. In the presence of embrittling species (I and Cd), stress corrosion cracking may occur.

The incidence of PCI failures depends on absolute power, rate of increase in power, duration of the power increase, previous power history and burnup. Also, there is a power threshold below which failures do not occur. This power threshold is a function of fuel burnup.

For PCI to occur, both a chemical embrittling agent (fission products I and Cd) and high cladding stresses are necessary. High cladding stresses occur at the pellet-to-pellet interfaces where PCI cracks are most commonly found. Strain concentrations occur in the cladding at radial pellet crack locations. The strain concentration is enhanced where the strain, due to pellet cracks, is also at the location of strain at pellet-to-pellet interfaces. (see Figures 4.4-1, 2, and 3.)

4.4.3 PCIOMR Rules

The General Electric operational recommendations (PCIOMR) are used to reduce PCI failures. Below the threshold power at which PCI failure occurs, there are no limitations on the magnitude, or rate, of power increase. Above the threshold, slow rates of power increases are accomplished by flow control according to PCIOMR guidelines developed from tests in experimental reactors. Following the slow increase to power levels above the threshold a "preconditioned power" level is established which may be utilized for an extended period of time. The PCIOMR rules listed in Table 4.4-3 have significantly reduced PCI fuel failures.

4.4.4 Maintenance of PC Envelope

Initial preconditioning of the fuel, at the beginning of each cycle, cannot be avoided. The preconditioning process itself, namely the slow and controlled increase in local power levels above the preconditioning threshold, must occur at the prescribed rate. At the start of each fuel cycle, the first preconditioning ramp to full power is insufficient to precondition all of the fuel. This is due to some nodes being controlled and, as such, are operating at power levels below the preconditioning threshold. During the first control rod sequence exchange, these low power nodes become uncontrolled and require preconditioning. Hence, a second preconditioning ramp will be necessary. Upon completion of this second ramp, all the fuel will have had an opportunity to be preconditioned. Throughout the remainder of the operating cycle, utilization of proper envelope maintenance and flux shaping techniques will eliminate further preconditioning ramps from low power levels (50 to 75% of rated).

For the purpose of this discussion, the fuel in the core may be regarded as either "A" fuel or "B" fuel as determined by the bundle location in-core. If the bundle is uncontrolled at 50% control rod density in A sequence, then the bundle is A fuel. Likewise, B fuel is uncontrolled at 50% control rod density in B sequence. Note again that during reactor operation in A

sequence, all of the A fuel is uncontrolled. During B sequence operation, all of the B fuel is uncontrolled.

Refer to Figure 4.4-8. Assume a beginning-of-cycle startup in the A-1 sequence. At 1,000 MWd/t (core-averaged) cycle exposure, the controlling rod pattern is changed to the B1 sequence. At 2,000 MWd/t cycle exposure, the controlling rod pattern is changed to the A2 sequence and so on as shown. The actual ordering of A1/B1/A2/B2 sequence operation is not important. However, it is essential that the A and B sequences are alternately employed. The A1/B1/A2/B2 sequence that is illustrated here is just one such possibility. As explained later on, preconditioning time will be minimized if the control rod pattern in each sequence results in a bottom-peaked power distribution, preferably Haling or better, at all radial locations. During the beginning-of-cycle startup (Figure 4.4-4 and 5), all fuel will be limited to their exposure dependent preconditioning threshold values.

The exposed fuel will be most limiting due to its having the lowest threshold. There is a shortcut for the beginning-of-cycle startup. It is imperative that the power distribution in the initial sequence be properly bottom peaked. For high power density cores loaded with 7x7 fuel, attainment of a proper bottom peak at the beginning-of-cycle may require more than one preconditioning ramp. All other cores can attain the desired power distribution on the initial ramp.

Upon reaching rated power and completion of the 12-hour soak, the preconditioned envelope should be stored for all nodes. Those nodes which are controlled will not have benefitted from the preconditioning ramp just completed. Despite this envelope update, they shall remain limited in power level to their preconditioning threshold values. All of the remaining nodes are uncontrolled and if their peak pin power levels had been preconditioned above their threshold power levels, new preconditioned envelope values will be retained. All of the A fuel (assuming initial operation in A1 or A2 sequence per Figure 4.4-5) and some of the B fuel will therefore have had an opportunity to expand their preconditioned envelope. The A fuel bundles will now have a preconditioned envelope distribution similar to their axial power distribution with the exception of a few nodes near core top and core bottom for which the final power level is still below the preconditioning threshold. Figure 4.4-6 illustrates conversion of the axial power to segment preconditioned envelope values for the A fuel. As for the B fuel, some segments that are situated above the control blade tips may have their preconditioned envelope updated if their final power levels exceed the preconditioning threshold. The important aspect here is that the A fuel, which is wholly uncontrolled, has a valid bottom-peaked preconditioned envelope. Should the reactor be shut down during the first 1,000 MWd/t a rapid return to rated power with the same rod pattern will now be possible utilizing the preconditioned envelope stored at the beginning-of-cycle. If a slower return to rated power is acceptable, it would be best to start up in a new sequence (i.e., B1 or B2 if the beginning-of-cycle start up was in A1 or A2 sequence). This would postpone the sequence exchange scheduled for 1,000 MWd/t cycle exposure until 1,000 MWd/t plus the cycle exposure at the time of the reactor shutdown.

Just prior to reducing core flow and power level for a control rod sequence exchange at 1,000 MWd/t cycle exposure, the preconditioned envelope should again be updated for all nodes. The envelope stored at the beginning-of-cycle will have expired shortly after this power reduction. The preconditioned envelope update at this time constitutes envelope maintenance; the envelope validity will be extended for a second core average exposure of 1,000 MWd/t period. This step is important because it permits utilization of the bottom-peaked preconditioned envelope for the A fuel during the control rod sequence exchange and ensuing power ascension at 2,000 MWd/t cycle exposure.

Following the preconditioned envelope update at the completion of A1 sequence operation, the core thermal power is reduced and a control rod sequence exchange to the B1 sequence is performed. The power ascension in the B1 sequence rod pattern will again be a lengthy preconditioning process. This cannot be avoided because the B fuel segments which were controlled during the A1 sequence operation are now uncontrolled. This fuel will require preconditioning from their preconditioning threshold values.

As in the beginning-of-cycle A1 sequence rod pattern development, it is essential that the necessary time be scheduled to ensure a proper, bottom- peaked power distribution during rated power operation in the new B1 sequence rod pattern. If time is going to be spent on preconditioning, it will be best utilized if the bottom of the core is being preconditioned.

Following this B1 sequence preconditioning envelope update, all of the fuel bundles will have had an opportunity to have its entire axial length preconditioned. The A fuel during A sequence operation; the B fuel during B sequence operation. The preconditioned enveloped formed reflects the maximum power level for each and every fuel segment in the core from either A or B sequence. This resultant preconditioned enveloped is referred to as a composite envelope.

As was the case during the first 1,000 MWd/t period of cycle operation in the A1 sequence, should the reactor scram or be shut down during the present B1 sequence operation, a rapid return to rated power will be possible.

At the close of the 1,000 MWd/t cycle operation in the B1 sequence, it is necessary to update the preconditioned envelope for those nodes and only for those nodes that were updated earlier during the B1 sequence operation. OD-11 has the capability to distinguish these nodes from all other nodes via the nodal delta exposure histogram edit of option 1. (All of the other nodes would have to have been updated at the end of the A1 control rod sequence operation -- the option 1 edit will show the largest value of delta exposure for these nodes. Those nodes that were updated during B1 control rod sequence operation will have smaller values of delta exposure as their preconditioned envelope values were updated more recently.) By updating the B1 sequence nodes, the preconditioned envelope for these nodes will be maintained for another 1,000 MWd/t. That is, their preconditioned values will be valid until the control rod sequence exchange to the B2 sequence and the ensuing power ascension at 3000 MWd/t cycle exposure.

At 2,000 MWd/t cycle exposure, core thermal power is reduced, the control rod pattern is changed to the A2 sequence and core thermal power is increased to rated. During this maneuver, all nodal powers are limited to their preconditioned envelope values. Only those nodes which did not operate at a power level above the threshold level during the A1 and B1

4.5 LOSS OF ALL AC POWER (STATION BLACKOUT)

Learning Objectives Viewgraph

Learning Objectives :

1. Define the term station blackout.
2. Describe the impact a station blackout would have when combined with an accident.
3. Describe the primary method available to mitigate the consequences of a station blackout.
4. List the two major classifications Boiling Water Reactors have been divided into for discussing station blackouts.

4.5.1 Introduction

GDC in Appendix A of 10CFR50

The general design criteria (GDC) in Appendix A of 10CFR50 **establish the necessary design, fabrication, construction, testing and performance requirements for structures, systems, and components important to safety**; that is, structures, systems and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. GDC 17 "Electric Power Systems" **requires that an onsite and offsite electric power system shall be provided to permit functioning of structures, systems and components important to safety.** These structures, systems and components are required to remain functional to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences. The GDC goes further to specify additional requirements for both the onsite and offsite electrical power distribution systems to **ensure both their availability and reliability.**

GDC 17 "Electric Power Systems"

The establishment of GDC 17 was considered sufficient to ensure that commercial nuclear power plants could be built and operated without undue risk to the health and safety of the public. The likelihood of a simultaneous loss of offsite and onsite sources of ac power was considered incredible and therefore did not have to be considered in plant design or accident analysis. Evaluation of plant data and events along with insights developed from PRA analysis have led to the development and implementation of additional regulatory requirements addressing station balckout.

Figure 4.5-1

(Class 1E) Classification :
IEEE calss1E is the safety classification given to electrical equipment and systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling and containment and reactor heat removal, or are otherwise essential in preventing significant release of radioactive material to the environment.

Figure 4.5-2

Figure 4.5-3

4.5.2 Description of Electrical Distribution System

A diagram of a typical offsite power system used at a nuclear plant is shown in Figure 4.5-1. During plant operation, power is supplied to the Class 1E (onsite) distribution system from the output of the main generator. In the event of a unit trip, the preferred source of power to the onsite distribution system would be the offsite grid. If offsite power is available, automatic transfer to the preferred power source will ensure a continuous source of ac power to equipment required to maintain the plant in hot standby and remove decay heat from the core. If offsite power is not available due to external causes such as severe weather or equipment failure, the onsite distribution system would sense the undervoltage condition and initiate a transfer to the onsite (standby) power source. Figure 4.5-2 shows a typical onsite emergency ac power distribution system. In the event that an undervoltage condition is sensed on the emergency buses following a unit trip, the system is designed to open all supply breakers to the buses, disconnect all unnecessary loads, start the emergency diesel generators and reconnect all loads necessary to maintain the plant in a stable hot shutdown condition. If the onsite emergency ac power source is not available to re-energize the onsite system, a station blackout has occurred.

4.5.3 Offsite Power Systems

On November 9, 1965, the northeastern U.S. experienced a power failure which directly affected 30 million people in the U.S. and Canada. On July 13, 1977, New York City experienced a blackout, following lightning strikes in the Indian Point 3 switchyard causing the reactor to scram and the plant to lose offsite power. No Federal regulation of the reliability of the bulk power supply was provided by the Federal Power Act of 1935 and none was subsequently approved following either the 1965 or the 1977 incidents. The reliability of the bulk power supply (interconnections) is the responsibility of the North American Electrical Reliability Council through its member Reliability Councils. These Councils are made up of members representing the electric power utilities which engage in bulk power generation and transmission in the United States, Canada, and Mexico.

Figure 4.5-3 Shows the geographic locations of the member councils throughout the United States and the various interconnections sections. Interconnections is a strategy for providing power from the plants via an interconnected transmission network to the entities that resell it to the consumer via a distribution network. The Western Interconnection is composed of one reliability Council, Western Systems Coordinating Council. The Eastern Interconnection is comprised of East Central Electric Reliability Coordination Agreement, Mid-Atlantic Area Council, Mid-America Interpool Network, Mid-America Power Pool, Northeast Power Coordination Council, Southeastern Electric Reliability Council, and Southwest Power Pool. The Texas Interconnection is also composed of one reliability Council, Electric Reliability Council of Texas.

load management procedures for Mid-Atlantic Area Council

The objectives for each Reliability Council vary but, whether explicitly stated or implied in context, the **Reliability Councils' operating philosophy is to prevent a cascading failure, provide reliable power supplies, and maintain the integrity of the system.** Long-term and short-term procedures are in place nationwide to project demand, to provide for reserves to meet peak demand, and to provide for both likely and unlikely contingencies when demand exceeds capacity and other emergencies. These **procedures include a load reduction program and automatic actuation to prevent collapse of the grid.** The load management procedures for mid-Atlantic Area Council consist of:

- Curtailment of nonessential power company station light and power (power plants)
- Reduction of controllable interruptible/reducible loads
- Voltage reductions **(brownouts)**
- Reduction of nonessential load in power company buildings (other than power plants)
- Voluntary customer load reduction
- Radio and television load reduction appeal
- Manual load shedding **(rotating blackouts)**
- Automatic actuation of underfrequency relays which shed 10 percent of load at 59.3 Hz, and additional 10 percent at 58.9 Hz, and an additional 10 percent at 58.5 Hz.

Other procedures allow disconnecting from the grid areas which have generating units that are capable of supplying local loads, but would trip if connected to a degrading grid.

In addition, emergency procedures are provided for the safe shutdown and restart of the system. Because many plants cannot be restarted without external power, "black start" units are available at various locations as determined by the utility. The black start units are capable of self-excitation: therefore, they restart and produce power to restart other units. The typical black start capability is comprised of diesel generators, combustion turbine units, conventional hydro units, and pump storage units. Normal operating procedures for pump storage hydro plants require maintaining sufficient water in the upper reservoir at all times to provide for system startup power. Satisfactory tests have been conducted to prove the capability of black start of conventual hydro, pumped storage hydro, and some steam and combustion turbine units to provide system startup power.

Grid Characteristics

4.5.3.1 Grid Characteristics

To more fully explain grid operation, the following concepts will be discussed: demand, capacity, reserve margin, age of power plants, and constraints on transmission lines.

Demand

Demand

Figure 4.5-4

Demand is the amount of electricity that the customer requires. The demand for electricity varies with the hour of the day, day of the week, and month of the year due to factors such as area temperature and humidity. When demand is greatest, it is said to "peak". Figure 4.5-4 shows the peak season, months, and percentage by which the peak exceeds the average demand. Capital letters denote major peaks, lower case denotes minor peaks. The percentage by which the peak exceeds the average demand gives insight into the importance of reserve margin in the area. Peak seasonal demand occurs in the summer for most areas of the country and in the winter in others.

To meet expected demand, utilities establish a base load (the amount of electricity they need to produce continuously) and an operating reserve for responding to increased demand. This operating reserve is called spinning or non-spinning reserve and can be loaded up to its limit in ten minutes or less. Spinning reserve is already synchronized to the grid, while non-spinning reserve is capable of being started and loaded within ten minutes. In addition to the spinning and ten minute non-spinning reserve some areas also have thirty minute reserve equipment.

Peak demand is the average or expected peaks estimated by combining such factors as previous use, the number of new customers, and weather forecasts. Demand forecasting is not done on a worst case scenario. It does not anticipate the demand during unusually severe weather or other unforeseeable factors which may affect demand.

January 18, 1994 - severe weather effects on demand

An example of severe weather effects on demand (and capacity) occurred on January 18, 1994, in Pennsylvania, New Jersey, and Maryland as well as Delaware, the District of Columbia, and Virginia. The temperature began to drop from approximately 35°F, at 5 a.m. to 8°F, at midnight. Electric demand in the afternoon and evening increased inversely with the temperature when it was expected to drop with the change in usage from commercial to residential. Because the temperature decreased to atypical values, the increase in residential demand exceeded the decrease in commercial demand, peaking at 7:00 p.m., and remained higher than the daytime peaks through midnight of the following day.

Utilities began emergency procedures to reduce demand. Emergencies were declared in Pennsylvania, Maryland, and the District of Columbia. Government offices and many businesses closed early on January 19 and remained closed on January 20. The emergency ended by midday on January 21, though some voltage reductions continued into the evening.

When demand is projected to exceed supply as it did in the January 18, 1994 cold spell, utilities purchase power from adjacent systems. In this case, these systems were also strained by the same cold weather problems; but the New York Power Pool did reduce voltage to its customers and imported power from the New England Power Pool and Canada in order to assist the effected area.

Demand for electricity by nuclear power plants usually occurs when the unit is not producing enough power to supply house loads which may include the safety related systems. Power to start up must also be supplied to the nuclear unit's generator. Offsite power for nuclear plants is not included in the utilities's load management program, but it may be affected by an automatic actuation in response to a grid fault. That is, a nuclear plant's voltage will not be reduced, nor will the plant load shed by the load management schemes; however, grid faults have caused nuclear plants to be isolated from the grid.

Capacity

Reserve Margin

Capacity

Capacity is the amount of electricity that the utility can produce or buy. A utility generates electricity by various means: steam turbines, gas turbines, internal combustion engines, jet engines, hydro turbines, and number of other means. Additional electricity may be furnished by co-generation units and non-utility generators. Typically, co-generation units are run by a company that produces the electricity for its own use. Non-utility generators may be co-generators, but are usually power production facilities, built and run by companies which are not regulated utilities. They currently sell the power that they produce to a utility. **The Capacity and related data for various areas can be seen on Figure 4.5-5.**

Reserve Margin

Reserve margin is the extra electrical capacity that the utility maintains for periods when the demand is unexpectedly high. In mid-afternoon on a hot summer day in July about anywhere in the country, reserve margins are reduced. Utilities must then resort to demand management: urging conservation, reducing voltage (brownouts), and load shedding (rotating blackouts) if additional power cannot be purchased.

The ability to purchase power is limited by the availability and adequacy of transmission lines. Although transmission lines can carry current in excess of rated maximum, attempts to increase the current beyond the setpoint of the protective system would result in the protective system opening the breakers and isolating the lines.

Past events have shown that factors such as unit availability and transmission line capacity affect the adequacy of reserve margin that is actually available for use. Improving unit availability and transmission line reliability are principal methods specified by Councils for maintaining adequate reserve margin. In addition, bringing units under construction on line and purchasing power are viable means of improving reserve margin.

AEOD draft report entitled "Grid Performance Factors"

Plant Age

An evaluation of reserve margins around the United States was performed and published in an AEOD draft report entitled "Grid Performance Factors" [AEOD S96-XX, September 1996]. The report showed that different councils use different methods and have dissimilar acceptability levels for reserve margin. Utilities do not all measure adequacy of reserves by the numbers. Evaluations of reserve margin in an AEOD document (Grid Performance Factors) show that one council is not satisfied with its projected 15 to 20 percent reserve margin, another is satisfied with 20 to 25 percent, while another council measures its reserve margin in percentage of peak demand and percentage of the size of the largest unit in its system. From these varying evaluations of adequacy of reserve margin, the following generalizations can be made: the minimum adequate percentage is 15 percent, reserves below 10 percent of total capacity are unacceptably low, and reserves above 25 percent should be more than adequate for any abnormal situation. Low reserves indicate a potential for problems.

Plant Age

With approximately 38 percent of the United States electricity generated by plants 26 years or older, age has the potential to become a factor in grid stability. Many newer plants are large, producing more megawatts from fewer plants. This concentration of generation can lead to stability problems. When the large plant trips, the nearby plants must pick up the load. In addition, the protective schemes at smaller older plants may not be effective in preventing damage to aging plants and thus further affect grid operation. Most of today's distribution system controller equipment, such as mechanical reclosures, require six cycles to react to a line fault which is not fast enough to provide the virtually instantaneous switching needed to keep sensitive equipment operating properly.

Constraints on Transmission Lines

Thermal/Current Constraints

Constraints on Transmission Lines

The amount of power on a transmission line is the product of the voltage and the current and a hard to control factor called the "power factor", which is related to the type of loads on the grid. Additional power can be transmitted reliably if there is sufficient available transfer capability on all lines in the system over which the power would flow to accommodate the increase. There are three types of constraints that limit the power transfer capability of the transmission system:

- thermal/current constraints,
- voltage constraints, and
- system operating constraints.

Thermal/Current Constraints

Thermal limitations are the most common constraints that limit the capability of a transmission line, cable, or transformer to carry power. The resistance of transmission lines causes heat to be produced. The actual temperatures occurring in the transmission line equipment depend on the current and ambient weather conditions (temperature, wind speed, and wind direction) because the weather effects the dissipation of the heat into the air. The thermal ratings for transmission lines, however, are usually expressed in terms of current flows, rather than actual temperatures for ease of measurement. **Thermal limits are imposed because overheating leads to two possible problems:**

- **the transmission line loses strength because of overheating which can reduce the expected life of the line, and**
- **the transmission line expands and sags in the center of each span between the supporting towers. If the temperature is repeatedly too high, an overheated line will permanently stretch and may cause clearance from the ground to be less than required for safety reasons.**

High voltage lines can sag 6 to 8 feet between support towers as they are heated by high current flow and hot weather, and allow flashover between the high voltage line and trees.

August 10, 1996 power outage

Voltage Constraints

Following the August 10, 1996 power outage that affected the western United States, a press release was issued by the Western Systems Coordinating Council on September 25, 1996. The investigation suggests that in all likelihood, the disturbance could have been avoided if contingency plans had been adopted to minimize the effects of an outage of the Keeler-Allston 500 KV line in the Pacific Northwest. In addition, the task force determined that the loss of the McNary generating units and inadequate tree trimming practices, operating studies, and instructions to dispatchers played a significant role in the severity of the event.

August 11, 1999

Prior to the flash over from the high voltage line to a tree, the interconnected transmission system was knowingly being operated in a manner that was not in compliance with the WSCC reliability criteria. In addition, the loss of the 13 McNary hydroelectric generating units in the northwest was a major factor leading to the outage of the transmission lines (Pacific Intertie) between the Pacific Northwest and California.

Voltage Constraints

Voltage, a pressure like quantity, is a measure of electromotive force necessary to maintain a flow of electricity on a transmission line. **Voltage fluctuations can occur due to variations in electricity** demand and to failures on transmission or distribution lines. If the maximum is exceeded, short circuits, radio interference, and noise may occur. Also, transformers and other equipment at the substations and/or customer facilities may be damaged or destroyed. Minimum voltage constraints also exist to prevent inadequate operation of equipment. Voltage on a transmission line tends to "drop" from the sending point to the receiving end. The voltage drop along the ac line is almost directly proportional to the reactive power flows and line reactance. The line reactance increases with the length of the line. Capacitors and inductive reactors are installed, as needed, on lines to control the amount of voltage drop. This is important because voltage levels and current levels determine the power that can be delivered to the customers.

On August 11, 1999, the Callaway nuclear plant experienced a repture of a reheater drain tank line. As a result, the plant operators initiated a manual reactor scram, which required offsite power to supply house loads. During this period, the electrical grid had large power flow from the north to south through the switchyard. The power flow, coupled with a high local demand and the loss of the

Callaway generator, resulted in switchyard voltage at the site dropping below the minimum requirements for 12 hours. Although offsite power remained available during the transient, the post trip analysis indicated that in the event, 4160 V distribution voltage may have been below the setpoint of the second level undervoltage relays separating the loads from offsite power. Similar events at Callaway and other nuclear power plants identified additional combinations of main generator unavailability, line outages, transformer unavailability, high system demand, unavailability of the local voltage support, and high plant load the could result in inadequate voltages. Common among the events is the inability to predict the inadequate voltage through direct readings of plant switchyard or safety bus voltages, with out also considering grid and plant conditions and their associated analyses.

Operating Constraints

Operating Constraints

The operating constraints of bulk power systems stem primarily from concerns with security and reliability. These concerns are related to maintaining the power flows in the transmission and distribution lines of a network. Power flow patterns redistribute when demands change, when generation patterns change, or when the transmission or distribution system is altered due to a circuit being switched out of service.

When specific facilities frequently experience disturbances which unduly burden other systems, the owners of the facility are required by their Council to take measures to reduce the frequency of the disturbances, and cooperate with other utilities in taking measures to reduce the effects of such disturbances. **The Councils have the right to enforce the agreement made within the Council framework.**

On August 13, 1996, the amount of electricity transmitted from the Northwest to power hungry California was cut 25 percent to reduce the chances of another blackout similar to the August 10, 1996 event. The reduction amounted to approximately 1,200 megawatts.

Learning Objective

1. Define the term station blackout.

4.5.4 Station Blackout

A station blackout is defined as **"the complete loss of alternating current (ac) electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e. loss of the offsite electric power system concurrent with turbine trip and unavailability of the onsite emergency ac power system)."**

Because many of the safety systems required for reactor core cooling, decay heat removal, and containment heat removal depend on ac power, the consequences of station blackout could be severe. In 1975, the Reactor Safety Study (WASH-1400) demonstrated that station blackout could be an important contributor to the total risk from nuclear power plant accidents.

This potential increase of risk, combined with increasing indications that onsite emergency power sources (diesel generators in most cases) were experiencing higher than expected failure rates, led the NRC to designate "Station Blackout" as an unresolved safety issue (USI). USI A-44 was established in 1979 and the task action plan that followed concentrated on the analysis of the frequency and duration of loss of offsite power events, and the probability of failure of onsite emergency ac power sources. Other areas of interest included the availability and reliability of decay heat removal systems which are independent of ac power, and the ability to restore offsite power before normal decay heat removal equipment (equipment that relies on ac power) failed due to harsh environment. If the results of the study and analyses demonstrated that the likelihood of a station blackout was significant, then the conclusions would be used as a basis for additional rule making and required design changes as necessary to protect the public health and safety. If safety improvements were indeed necessary, it would be more feasible to identify and initiate improvements with onsite power sources than with either offsite power sources or onsite equipment that required ac power to function. Offsite power source reliability is dependent on several factors such as regional grid stability, potential for severe weather conditions and utility capabilities to restore lost power, all of which are difficult to control. Ultimately, the ability of a plant to withstand a station blackout depends upon the decay heat removal systems, components, instruments, and controls that are independent of ac power. The results of the "Station Blackout" study were published in NUREG-1032.

NUREG-1032 divides loss of offsite power operational experiences into three types:

- plant-centered events which had an impact on the availability of offsite power,
- grid blackouts or perturbations which had an impact on the availability of offsite power, and
- weather-related and other events which had an impact on the availability of offsite power.

Learning Objective

2. Describe the impact a station blackout would have when combined with an accident.

Learning Objective

3. Describe the primary method available to mitigate the consequences of a station blackout

4.5.5 Plant Response

The immediate consequences of a station blackout are not severe unless they are accompanied by an accident such as a loss of coolant accident. If the condition continues for a prolonged period, the potential consequences to the plant and public health and safety can be serious. The combination of core damage and containment overpressurization could lead to significant offsite releases of fission products. **Any design basis accident in conjunction with a station blackout reduces the time until core damage and release will occur.**

Without systems designed to operate independently of ac power, the only way to mitigate the consequences of a station blackout is to take steps to minimize the loss of reactor vessel inventory and quickly restore electrical power to replenish the lost inventory. This will ensure the ability to remove decay heat from the core and prevent fuel damage.
The primary method available to mitigate a station blackout with current plant design features is to initiate a controlled cooldown of the reactor. This evolution is covered in the existing Emergency Procedure Guidelines.

4.5.6 Interim Response by NRC

Interest over loss of all ac power (station blackout) intensified in mid-1980 following license hearings for the operation of the St. Lucie Unit 2 plant in southern Florida. The concern was that with the plant being located in an area subject to periodic severe weather conditions (hurricanes) and questionable grid stability, the probability of a loss of offsite power would be much higher than normal. The Atomic Safety and Licensing Appeal Board (ASLAB) concluded that station blackout should be considered a design basis event for St. Lucie Unit 2. Since the task action plan for USI A-44 was expected to take a considerable amount of time to study the station blackout question, the ASLAB recommended that plants having a station blackout likelihood comparable to that of St. Lucie be required to ensure that they are equipped and their operators are properly trained to cope with the event. NRR changed the construction permit of St. Lucie Unit 2 to include station blackout in the design basis and required Unit 1 to modify its design even though preliminary studies showed that the probability of a station blackout at St. Lucie was not significantly different than for any other plant. Interim steps were taken by NRR to ensure other operating plants were equipped to cope with a station blackout until final recommendations were formulated regarding USI A-44.

Recommendations for improvements to the emergency diesel generators had already been established based on studies of DG reliability (NUREG/CR-0660) and were being implemented for plants currently being licensed. A program for implementing those recommendations at operating reactors was developed, including Technical Specifications improvements. It was recognized that improvements to DG reliability was the most controllable factor affecting the likelihood of a station blackout and could only serve to reduce the probability of occurrence. Generic Letter 81-04 was issued to all operating reactors which required licensees to verify the adequacy of or develop emergency procedures and operator training to better enable plants to cope with a station blackout. Included would be utilization of existing equipment and guidance to expedite restoration of power from either onsite or offsite.

4.5.7 Regulation Changes

Based on information developed following the issuance of USI A-44, a proposed change to NRC regulations and regulatory guidance was published in March 1986 for comment. The rule change consisted of a definition of "station blackout"and changes to 10CFR50.63 which would require that all nuclear power plants be capable of coping with a station blackout for some specified period of time. The time period would be plant specific and would depend on the existing capabilities of the plant as well as a comparison of the individual plant design with factors that have been identified as the main contributors to the risk of core melt resulting from a loss of all ac power. These factors include the redundancy and reliability of onsite emergency ac power sources, frequency of loss of offsite power and the probable time needed to restore offsite power. With the adoption of 10CFR 50.63, all licensees and applicants are required to assess the capability of their plants to cope with a station blackout and have procedures and training in place to mitigate such an event. Plants are also required to cope with a specified minimum duration station blackout selected on a plant specific basis. In addition, Regulatory Guide 1.155 provides guidance on maintaining a high level of reliability for emergency diesel generators, developing procedures and training to restore offsite and onsite emergency ac power and selecting a plant specific minimum duration for station blackout capability to comply with the proposed amendment. A time duration of either 4 or 8 hours would be designated depending on the specific plant design and site related characteristics.

Learning Objective

4. List the two major classifications Boiling Water Reactors have been divided into for discussing station blackouts

4.5.8 BWR Application

To assess station blackout, BWRs have been divided into two functionally different classes: (1) **those that use isolation condensers for decay heat removal but do not have makeup capability independent of ac power (BWR-2 and 3 designs), and (2) those with a reactor core isolation cooling (RCIC) system and either a high pressure coolant injection (HPCI) system or high pressure core spray (HPCS) system with a dedicated diesel, either of which is adequate to remove decay heat from the core and control water inventory in the reactor vessel, independent of ac power (BWR-4, 5, and 6 designs).**

The isolation condenser BWR has functional characteristics somewhat like that of a PWR during a station blackout in that normal make up to the reactor is lost along with the residual heat removal (RHR) system. The isolation condenser is essentially a passive system that is actuated by opening a condensate return valve. The isolation condenser transfers decay heat by natural circulation.

The shell side of the condenser is supplied with water from a diesel driven pump. However, replenishment of the existing reservoir of water in the isolation condenser is not required until 1 or 2 hours after actuation. It is also possible to remove decay heat from this type of BWR by depressurizing the primary system and using a special connection from a fire water pump to provide reactor coolant makeup. This alternative would require greater operator involvement. Some BWR-3 designs may have installed a RCIC system, thus providing reactor makeup to the already ac power independent decay heat removal function of the isolation condenser cooling system.

A large source of uncontrolled primary coolant leakage will limit the time the isolation condenser cooling system can be effective. If no source of makeup is provided, the core will eventually become uncovered. A stuck open relief valve or reactor coolant recirculation pump seal leak are potential sources for such leakage. When isolation condenser cooling has been established, the need to maintain the operability of such support systems as compressed air and dc power is less for this type of BWR than it is for a PWR. However, these systems would eventually be needed to recover from the transient.

BWRs can establish decay heat removal by discharging steam to the suppression pool through relief valves and by making up lost coolant to the reactor vessel with RCIC and HPCI or HPCS. In these BWR designs, decay heat is not discharged to the environment, but is stored in the suppression pool. Long term heat removal is by the suppression pool cooling mode of the residual heat removal system. The duration of time that the core can be adequately cooled and covered is determined, in part, by the maximum suppression pool temperature for which successful operation of decay heat removal systems can be ensured during a station blackout event and when ac power is recovered.

At high suppression pool temperatures (around 200^{0}F) unstable condensation loads may cause loss of suppression pool integrity. Another suppression pool limitation to be considered is the qualification temperature of the RCIC and HPCI pumps which are used during recirculation. Suppression pool temperatures may also be limited by net positive suction head (NPSH) requirements of the pumps in the systems required to effect recovery once ac power is restored.

All light water reactor designs have the ability to remove decay heat for some period of time. The time depends on the capabilities and availability of support systems such as sources of makeup water, compressed air, and dc power supplies. Also considered is degradation of components as a result of environmental conditions that arise when heating, ventilation and air conditioning (HVAC) systems are not operating. System capabilities and capacities are normally set so the system can provide its safety function during the spectrum of design basis accidents and anticipated operational transients, which does not include station blackout.

Perhaps the most important support system for the plant is the dc power system. During a station blackout, unless special emergency systems are provided, the battery charging capability is lost. Therefore, the capability of the dc system to provide instrumentation and control power can significantly restrict the time that the plant is able to cope with a station blackout. Dc power systems are generally designed to provide specific load carrying capacity in the event of a design basis accident with battery charging unavailable. However, dc system loads required for decay heat removal during a total loss of ac power are somewhat less than the expected design basis accident loads. Therefore, most dc power systems in operation today have the capacity to last longer during a station blackout than during a design basis accident.

Actions necessary to operate systems during a station blackout would not be routine. The operator would have less information and operational flexibility than is normally available during most other transients requiring a reactor cooldown.

In BWRs with isolation condensers, the isolation condenser appears to need less operator attention than RCIC and HPCI systems. However, operators would have to insure that automatic depressurization does not occur and that makeup to the isolation condenser is available within approximately 2 hours after the loss of ac power. For BWRs with HPCI or HPCS and RCIC, the operator must control both reactor pressure and level. This may require simultaneous actuation of relief and makeup systems.

4.5.9 Accident Sequence

Figure 4.5-6

Figure 4.5-6, taken from NUREG-1032, shows a BWR Mark I containment station blackout accident sequence progression. In this scenario, station blackout occurs at time zero (t_o). The reactor coolant system pressure and level are initially maintained within limits by RCIC and/or HPCI and relief valve actuation. The suppression pool and drywell temperatures begin to rise slowly; the latter is more affected by natural convection heat transport from hot metal (vessel and piping) of the primary system. After 1 hour, because ac power restoration is not expected, the operator begins a controlled depressurization of the primary system to about 100 psi. This causes a reduction in reactor coolant temperature from about 550^0F to 350^0F, which will reduce the heat load to the drywell as primary system metal components are also cooled. The suppression pool temperature increase is slightly faster than it would have been without depressurization. Drywell pressure is also slowly increasing. At about 6 hours (**t_1**), dc power supplies are depleted and HPCI and RCIC are no longer operable. Primary coolant heatup follows, which increases pressure and level to the SRV setpoint. Continued core heatup causes release of steam. This eventually depletes primary coolant inventory to the point that the core is uncovered approximately 2 hours after loss of makeup (**t_2**). Core temperature then begins to rise rapidly, resulting in core melt and vessel penetration within another 2 or 3 hours (**t_3**). During the core melt phase, containment pressure and temperature rise considerably so that containment failure occurs nearly coincident with vessel penetration, either by loss of electrical penetration integrity (shown at **t4**) or by containment overpressure after high pressure core melt ejection, around 11 hours into the accident.

4.5.10 General Containment Information

The BWR Mark I and Mark II containments offer some pressure suppression capability during a station blackout accident, but after a core melt, they may fail by one of two modes. Either mechanical or electrical fixtures in the penetrations will fail because they are not designed for the pressure and temperature that will follow or ultimately, overpressure and subsequent rupture of the containment will occur. Because these containments are generally inerted, hydrogen burn is not considered a likely failure mode. Mark III containments are low pressure, large volume containments, and failure is estimated to result primarily due to overpressurization.

4.5.11 PRA Insights

Plant staff have typically considered the low probability of numerous failures occurring at the same time as an incredible situation. However, the two examples that follow illustrate that multiple failures have existed simultaneously at licensed facilities.

On March 25, 1989, Dresden Unit 3 experienced a loss of offsite power. The plant also lost both divisions of low pressure coolant injection (LPCI), instrument air (IA), and one division of the containment cooling water system for over one hour. In addition, the high pressure coolant injection (HPCI) system failed to start due to a partially completed manual initiation sequence. The isolation condenser (IC) was used to provide core cooling and decay heat removal. Water makeup to the IC was provided by the condensate system. The relative significance of this event (LER 249/89-001) compared with other postulated events at Dresden is indicated in the diagram below:

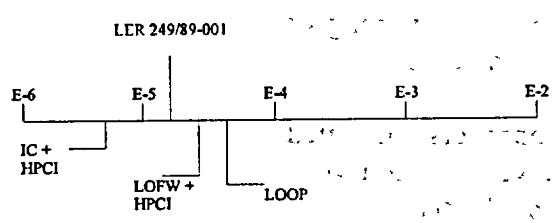


Figure 1

Where:
IC - isolation condenser
LOFW- loss of feedwater
LOOP - loss of offsite power

The conditional probability of severe core damage for this event is 1.3X 10 -5. The dominant sequence associated with the event (highlighted on figure 4.5-7), involves simultaneous failures of an SRV to close, HPCI to start, and the operators to depressurize using ADS. Note that the shutdown cooling system for Dresden is separate from LPCI and redundant capability exists for decay heat removal.

On June 17, 1989, Brunswick 2 experienced a loss of offsite power. The control room previously received a ground fault annunciator alarm on the Standby Auxiliary Transformer (SAT) and had called the transmission system maintenance team to initiate repairs. The plant recirculation pumps were being powered from the SAT per procedure to minimize pump seal failure caused by frequent tripping of the recirculation pumps.

The operators had started a planned power reduction when a technician shorted out the transformer, which caused a loss of the SAT and eventually a dual recirculation pump trip. The operator manually scrammed the reactor in accordance with procedures. A dual recirculation pump trip requires the plant to be manually scrammed if the trip results in operation in the region of instability outlined in NRCB 88-07. The plant scram caused a loss of the unit auxiliary transformer and the loss of offsite power. While attempting to place the unit in cold shutdown, the outboard RHR injection valve was discovered stuck in the closed position. It was later determined that the valve disk had separated from the stem.

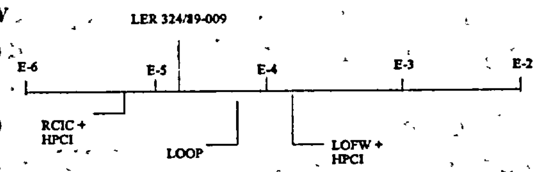
The conditional probability of severe core damage for this event is 3.6X10-5. The dominant accident sequence (figure 4.5-8) involves failure to recover offsite power in the short term, coupled with loss of emergency power and battery depletion. It should be noted that if PRA had been considered prior to working on the SAT, the plant staff could have identified that transferring pump power to the unit auxiliary transformer would have been highly beneficial. The relative significance of this event (LER 324/89-009) compared with other postulated events at Brunswick is indicated in the diagram below.

4.5.12 Risk Reduction

The process of developing a probabilistic model of a nuclear power plant involves the combination of many individual events (initiators, hardware failures, operator errors, etc.) into accident sequences and eventually into an estimate of the total frequency of core damage. After development, such models can also be used to assess the importance of individual events. Detailed studies have been analyzed using several event importance measures.

One such measure is the risk reduction importance measure. The risk reduction importance measure is used to assess the change in core damage frequency as a result of setting the probability of an event to zero. Using this measurement, the following individual events at Grand Gulf were found to cause the greatest reduction in core damage frequency if their probabilities were set to zero:

- Loss of offsite power initiating event. The



- Failure to restore offsite power in one hour. The core damage frequency would be reduced by approximately 70 percent.
- Failure to repair hardware faults of diesel generator in one hour. The core damage frequency would be reduced by approximately 46 percent.
- Failure of the diesel generator to start. The core damage frequency would be reduced by approximately 23 to 32 percent.
- Common cause failures to the vital batteries. The core damage frequency would be reduced by approximately 20 percent.

4.5.13 Summary

The electrical transmission infrastructure has been the subject of increasing stress over the past several decades. Electrical power demand continues to increase and is expected to double in the next thirty years. Progressive electric industry deregulation has produced great changes and uncertainty among energy providers. New electrical transmission lines are difficult to site and expensive to build, and with the economics of the electric power industry so uncertain, utilities have been working their systems harder and exploiting their built-in safety margins to meet growing demand and peak loads. The electrical utility industry restructuring associated with deregulation is resulting in the separation of responsibility for transmission systems and the actual power delivery to customers (line companies or distribution companies). Transmission companies are being structured to provide open access to power generators, distribution companies and end users. The distribution company provides the final link between the transmission company and the actual customers.

Station Blackout is one of the largest contributors to core damage frequency at BWRs. At all light water reactors operators have to be prepared to deal with the effects of a loss of and restoration of ac power to plant controls, instrumentation, and equipment. Although loss of all ac power is a remote possibility, it is necessary to address the problem both in training of personnel and equipment design. Extensive studies are being conducted to find ways of better understanding and coping with the effects of a total loss of ac power.

BWRs have such a large number of motor driven injection systems that a loss of electrical power implies loss of injection capability. This is why station blackout is consistently identified by PRAs to be the dominant core melt precursor for BWRs.

4.6 AIR SYSTEM PROBLEMS

Learning Objectives:

Objectives ---------------->

1. State two safety related functions performed by plant air systems.
2. List two sources of air system contamination.
3. List two causes (other than contamination) of air system failures.

Introduction

Many U.S. Boiling Water Reactor (BWR) plants rely upon air systems to actuate or control safety-related equipment during normal operation. However, at most BWRs, the air systems are not classified as safety systems. Plant safety analyses typically assume that nonsafety-related air systems become inoperable during abnormal transients and accidents, and that the air-operated equipment which is served fails in known, predictable modes. In addition, air-operated equipment which must function during transients or accidents are provided with a backup air (or nitrogen) supply in the form of safety grade accumulators to aid in continued system operation.

Air Problem Events ------------------->

Hatch 1986

On December 3, 1986, 140,000 gallons of radioactive water drained from the spent fuel pool at Hatch 1 and 2 due to deflated pneumatic seals resulting from a mispositioned air line valve.

Brunswick 1986

On December 24, 1986, Carolina Power and Light Company engineers discovered a potential for a common mode failure of all of the emergency diesel generators at Brunswick 1 and 2. They found that HVAC supply dampers for the diesel generator building would fail closed, due to the loss of air, during a loss of offsite power event. The dampers failing closed, reduces the air flow and causes the diesel generator control system to heat up. It was calculated that within one hour the air temperature in the diesel rooms would exceed the environmental qualification temperature of the control system.

Cooper 1989

On November 25, 1989, Cooper Nuclear Station experienced a closure of the main steam isolation valves which occurred as a result of a total loss of instrument air pressure. An instrument air dryer prefilter pipe ruptured causing low instrument air pressure, which in turn caused the outboard main steam isolation valves to drift closed and some of the control rods to drift into the core.

Consider the following effects the air system has on the Control Rod Drive System. If instrument air is lost, the control rods drift into the core as a result of the scram outlet valves failing open. Control rod drift can cause peaking problems and possible fuel failure even though the rods are moving in the safe direction.

Also, oil contamination of the air system has prevented control rods from scramming by preventing the scram solenoid valves from functioning correctly.

Typical Instrument Air System

A simplified diagram of a typical air system is shown in figure 4.6-1. The air system begins with air compressors that take suction from the room in which they are located, raise the pressure of the air to approximately 100 psi, and discharge the air to storage receivers. There are two or more 100% capacity air compressors which are powered from nonvital 480 Vac electrical busses. The compressors are controlled by pressure switches located on the instrument air receivers. During normal operation, one of the air compressors is in service with the redundant compressor in standby. The running compressor loads (compresses air) when the receiver pressure drops below a predetermined value (approximately 95 psi) and unloads when the receiver pressure reaches its normal operating pressure. If instrument air pressure decreases below 95 psi, the standby compressor(s) is/are started. Typically the standby compressor starts between 70 and 80 psi.

The receivers supply the air to instrument and service air headers. Instrument air passes through air dryers and filters prior to supplying various plant components. Dryers remove moisture from the air supply and filters remove foreign particles. The dryers and filters are necessary components because of the materials and small clearances of the internal moving parts of pneumatic equipment. Clean, dry, and oil free air is required for reliable trouble free operation. The air from the conditioning equipment is distributed throughout the instrument air system.

Have class come up with systems/components to satisfy objective #1

The instrument air system is subdivided by building location, i.e. turbine building, auxiliary building, fuel building, and containment building.

Objective #1

Reaactor Building

Refueling equipment
Containment isolation valves
Scram valves
Backup for nitrogen supply to SRVs and inboard MSIVs
RWCU F/Ds
HVAC

Turbine Building

Extraction steam system
Turbine iol cooling
Gen. Hydrogen cooling wate
Hotwell level control system
Heater drain valves
Feedwater regulating valves

Diesel building

Contains a dedicated ais system used for starting air, control air, HVAC uint operation

The turbine building instrument air supplies components such as the hotwell level control valves, turbine extraction steam and heater drain system, various valve actuators that control cooling water flow to generator hydrogen and oil systems, condensate system demineralizer valves, building heating and air conditioning, and the steam sealing system for the turbines. The reactor building instrument air loads include the outboard main steam isolation valves, control rod drive hydraulic system and various other components. The drywell air supply is use for the inboard main steam isolation valves, and equipment and floor drain isolation valves. The instrument air supply to the drywell is equipped with an automatic isolation valve that closes on a containment isolation signal. Of course, when an isolation occurs, the air supply header inside the containment will depressurize.

The service air system is used to supply air to components such as the demineralizer backwash and precoat system and hose stations for pneumatic tools. Many boiling water reactor plants utilize separate service air systems to meet this need.

Objective #2

Instrument Air System Problem Areas

Water Contamination

Water-moisture in system

Although the instrument air dryers are designed to remove water from the air system, moisture is one of the most frequently observed contaminants in the air system. Water droplets entrained in the air can initiate the formation of rust or other corrosion products which block internal passageways of electric to pneumatic converters resulting in sticking and/or binding of moving parts. In addition, water droplets can obstruct the discharge ports on solenoid air pilot valves (CRD hydraulic system), thus reducing their ability to function properly. Furthermore, moisture can cause corrosion of air system internal surfaces as well as the internal surfaces of equipment connected to the air system. Rust and other oxides have caused the exit orifices of pilot valves and other equipment to be totally blocked, resulting in degraded equipment operation or its complete loss. Additionally, rust particles on the inside of the piping/equipment have the potential to be dislodged during severe vibrations which could lead to simultaneous common mode failures of many downstream components.

Particulate contamination

Particulates

Particulate matter has prevented air from venting through discharge orifices of solenoid air pilot valves and valve operators. A clogged orifice changes the bleeddown rate, which affects the valve opening or closing times and could result in complete failure. Additionally, small particles have prevented electrical to pneumatic converters from functioning properly. Air dryer desiccant has been found in air pilot valve seals, preventing the valve from operating correctly.

Hydrocarbons and oil

Hydrocarbons

Hydrocarbon contamination of air systems can cause sluggish valve operations as well as complete loss of valve motion. Compressor oil has been observed to leave a gummy-like residue on valve internal components. This causes the valves to operate sluggishly, erratically, or completely fail to operate. Hydrocarbons have also caused valve seals to become brittle and stick to mating surfaces, thereby preventing valve motion. In some cases, parts of deteriorated seals were found in air discharge orifices of valves thus preventing the valve from operating correctly.

Objective #3

Types of failures
- rapid
- gradual
- under presure
- over pressure

Component Failures

Numerous components make up the plant service and instrument air system. The following paragraphs describe a few common failures and possible ramifications.

Air Compressors

In most plants, instrument air systems include redundant air compressors, but generally they are not designed as safety-grade or safety-related systems. As a result, a single failure in the electrical power system or the compressor cooling water supply can result in a complete loss of the air compressors. Because plants have redundant air compressors and automatic switching features, single random compressor failures usually do not result in a total loss of air. Most air system compressors are of the oil-less type. However, some plants do use compressors that require oil as a lubricant, and have experienced oil contamination of their air systems. Similarly, the temporary use of oil lubricated backup or emergency compressors without provisions for adequate filtration and drying can result in significant air system degradation.

Distribution System

Since most instrument air systems are not designated safety-grade, or safety-related, they are vulnerable to a single distribution system failure. For example, a single branch line or distribution header break could causing partial or complete depressurization of the air system.

Dryers and Filters

Single failures in the instrument air filtration or drying equipment can cause widespread air system contamination, resulting in common failures of safety-related er earlergged or broken air filter, a malfunctioning desiccant tower heater timer or plugged refrigerant dryer drain can cause desiccant, dirt or water to enter the air lines. As discussed earler, such contaminants could result in significant degradation, or even failure, of important air system components.

Safety Issue Definition

Compressed air degradation has the potential to affect multiple trains of safety-related equipment. Air system degradation includes (1) gradual loss of air pressure and (2) air under pressurization or over pressurization outside the design operating range of the associated equipment dependent on the air system. It is not clear what failure modes could result from these types of events. ACRS feels that although unresolved safety issue A-47 addressed sudden complete loss of air pressure, it did not adequately investigate the effects of air system degradation on safety-related equipment.

Regulation and Guidance

While no regulations specifically address degradation of instrument air systems, several general design criteria do provide requirements for safety-related structures, systems, and components. General design criterion (GDC) 1 states that structures, systems, and components important to safety must be designed, fabricated, and tested to quality standards commensurate with the importance of safety functions to be performed. GDC 5 requires that shared systems and components important to safety be capable of performing required safety functions.

Guidance provided in standard review plan (SRP) section 9.3.1 "Compressed Air Systems," states that all safety-related air-operated devices that require a source of air to perform safety-related functions be identified and reviewed. This requirement ensures that failure of an air system component or loss of the air source does not negate functioning of a safety-related system.

Guidance for testing of air systems is provided in Regulatory Guide 1.68.3, "Preoperational Operational Testing of Instrument and Control Air Systems". The guide requires tests to determine the response of air-operated or air-powered equipment to sudden and gradual pressure loss, through and including a complete loss of pressure. In addition, response of equipment to partial reductions in system pressure must be tested. Functional testing of instrument/control air systems important to safety should be performed to ensure that credible failures resulting in an increase in the supply pressure will not cause loss of operability. The system must also be able to meet the quality requirements of ANSI/ISA S7.4-1975, "Quality Standard for Instrument Air," with respect to the allowable amounts of oil, water, and particulate matter. If licensees of operating plants make modifications or repairs to their air systems, then their proposed restart testing program will be evaluated according to RG 1.68.3.

In 1988, the NRC issued Generic Letter 88-14, which requests that licensees perform a design and operations verification of their instrument air systems. The verification includes the following:

- Testing actual instrument air quality to ensure it is consistent with the manufacturer's recommendations for individual components served.
- Maintenance practices, emergency procedures, and training are adequate to ensure that safety-related equipment will function as intended on loss of instrument air.
- The design of the entire instrument air system including accumulators is in accordance with its intended function.
- Testing of air-operated safety-related components to verify that those components will perform as expected in accordance with all design basis events.

Generic Letter 88-14 does not address verification of the operation of safety-related component failure during gradual increasing or decreasing pressure.

NRC and Industry Programs

The NRC has issued several IE notices that address compressed air system-related failures that have occurred at several nuclear plants. IE Notice 81-38, "Potential Significant Equipment Failures Resulting From Contamination of Air-Operated Systems," reported the potential for air- operated systems to fail because of oil, water, desiccant, and rust contamination. IE Notice 82-25, "Failures of Hiller Actuators on Gradual Loss of Air Pressure," reported the failure of valves to move to a specified position on loss of air pressure. The actuators were depressurized gradually, rather than suddenly, resulting in the failure of the valves to move to their fail-safe position. IE Notice 88-24, "Failures of Air-Operated Valves Affecting Safety-Related Systems," reported failure of safety-related valves to assume their fail-safe positions upon deenergization of their respective solenoid valves. In this event, the maximum operating pressure differential for the valves was less than the operating pressure for the air system. In addition to the IE notices, the NRC created Generic Issue 43, " Reliability of Air Systems," and assigned it a high priority for evaluation. In a 1989 letter from ACRS to the NRC, ACRS stated that in light of the requirements of Generic Letter 88-14, they did not consider the resolution of Generic issue 43 adequate. In response, the NRC recommended that air system degradation be addressed as a separate issue.

Operating Experience

In 1987, AEOD completed a comprehensive review and evaluation of the potential safety implications associated with air system problems. This report identified the following specific deficiencies:

- The air quality capability of the instrument air filters and dryers does not always match the design requirements of the equipment using the air.
- Maintenance of instrument air systems is not always performed in accordance with manufacturer's recommendations.
- The air quality is usually not periodically monitored.
- Plant personnel frequently do not understand the potential consequences of degraded air systems.
- Operators are not well trained to respond to losses of instrument air, and the EOPs for such events are frequently inadequate.
- At many plants the response of key equipment to a loss of instrument air has not been verified to be consistent with the FSAR.
- Safety-related backup accumulators do not necessarily undergo surveillance testing or monitoring to confirm their readiness.
- The size and the seismic capability of safety-related backup accumulators at several plants have been found to be inadequate.

Design deficiencies were identified as the root causes of most air system problems. With the introduction of Individual Plant Examinations (PRA) and accident management requirements by the commission, these deficiencies can be discovered and corrected.

Shortly after the PRA program (April 1988) was begun at Fermi 2, a question arose concerning the safety impact resulting from operating the non-interruptible air system cross connected (division 1 with division 2). An analysis of the effects on core damage frequency showed that the risk from scenarios involving a transient and a loss of air could be reduced by a factor of 2 if the non-interruptible air system was operated cross connected.

Summary and Conclusion

Losses of instrument air have occurred in the industry. Failure of equipment and systems due to air system degradation discussed above have not been included in the plant safety analyses. Consequently, some plants with significant instrument air system degradation may be operating or may have operated with a much higher risk than previously estimated. Many plants do not have specific license requirements prohibiting operation with degraded air systems. Therefore, high confidence does not exist that all plants will voluntarily take corrective action to avoid plant operation with degraded air systems.

The results of NUREG/CR-5928 concluded that ISLOCA was not a risk for the BWR plant analyzed. Although portions of the interfacing systems are susceptible to rupture if exposed to full RPV pressure, these are typically pump suction lines that are protected by multiple valves.

4.7.5 Summary

In order to reduce the probability of this type of event even further, license changes have been made to the technical specifications that limit the maximum leak rate through isolation valves.

4.7 INTERFACING SYSTEM LOCA

Learning Objectives :
After studying this section, you should be able to:

1. Define the term "interfacing system LOCA (ISL)"

2. List the major interfacing lines for a BWR.

Introduction

Objective #1 --------------------->

The term "interfacing system LOCA" (ISL) ***refers to a class of nuclear plant loss of coolant accidents in which the reactor coolant system pressure boundary interfacing with a support system of lower design pressure is breached.*** This could cause an over pressurization and breach the support system, portions of which are located outside of the primary containment. Thus, a direct and unisolable coolant discharge path would be established between the reactor coolant system and the environment. Depending on the configuration and accident sequence, the emergency core cooling systems as well as other injection paths may fail, resulting in a core melt with primary containment bypassed.

The Reactor Safety Study, WASH-1400, identified an interfacing system LOCA accident in a PWR as a significant contributor to risk from the core melt accidents (event V). The event V arrangements were defined to be two check valves in series or two check valves in series with an open motor operated valve. Such valve arrangements are commonly used in PWRs but rarely in BWRs.

As a result of the WASH-1400 study and the TMI-2 accident, all light water reactors with operating license granted on or before February 23, 1980 were required to periodically test or continuously monitor the event V valves. The periodic test consisted of in-service leak rate testing of each check valve every time the plant is shutdown and/or each time either check valve is moved from the fully closed position.

Since early 1981, the Office of Nuclear Reactor Regulation (NRR) staff commenced back fitting operating reactors by requiring in-service leak rate testing of all pressure isolation valves that connect the reactor coolant system to lower pressure systems. On April 20, 1981, orders were sent to 32 PWRs and 2 BWRs which required leak rate testing of Event V valves.

In February 1985, the NRR staff established new acceptance criteria for leak rate testing. The leak rate of each valve must be no greater than one half gallon per minute for each nominal inch of valve size and no more than 5 gallons per minute for any particular valve.

The current leak rate testing requirements for pressure isolation valves on BWRs are as follows:

- At least once per 18 months.
- Prior to returning the valve to service following maintenance or replacement work.

Recent BWR operating experience indicates that pressure isolation valves may not adequately protect against over pressurization of low pressure systems. The over pressurization may result in the rupture of the low pressure piping. This event, if combined with failures in the emergency core cooling systems and other systems that may be used to provide makeup to the reactor coolant system, would result in a core melt accident with an energetic release outside the containment.

Following the coverage of the Definition of ISL have the calsss come up with a list of systems that fit the definition.

Interfacing Lines

The major interfacing lines discussed in the following sections include:

- LPCI injection lines
- shutdown cooling suction line
- shutdown cooling return line
- steam condensing supply lines to RHR heat exchanger
- reactor vessel head spray line
- high pressure core spray suction
- low pressure core spray line

LPCI Injection Line

The RHR system consists of two loops, (A & B). Each loop contains two pumps, associated valves; and piping to inject water from the suppression pool to the reactor vessel. Both loops A and B are used for multiple purposes (modes), such as shutdown cooling mode, steam condensing mode, containment spray mode, and suppression pool cooling mode.

Failure of a LPCI injection testable check valve and/or the normally closed injection valve would over pressurize the RHR system piping and cause failure of that loop. The relief valve located between the inboard and outboard injection valves has a capacity of approximately 185 gpm and a set pressure of 500 psig. The relief valve is capable of handling the flow from the testable check valve bypass valve, but not the amount of flow that would result from a failure of the testable check valve to close.

Shutdown Cooling Suction Line

The suction line from recirculation loop B contains an inboard and outboard isolation valve and an individual pump isolation valve. The containment isolation valves automatically close if reactor vessel reaches level 3 or reactor pressure increases to 135 psig. Failure of the containment isolation valves to close would allow the low pressure piping to fail causing an interfacing system LOCA.

Steam Condensing Supply Lines to RHR Heat Exchanger

The steam condensing mode of the RHR system can be manually placed in service following a reactor trip and would be capable of condensing all of the steam generated within 1.5 hours following the trip. The steam is removed via the HPCI steam line outside of the drywell and directed to the RHR heat exchanger where it is condensed. The condensate is then returned to the suction line of the RCIC or the suppression pool depending on the water quality.

Each RHR heat exchanger shell is protected against over pressure by a relief valve located on the steam inlet piping. Each relief valve is set at 500 psig and is sized to limit pressure to 550 psig with the steam pressure control valve fully open and steam pressure equal to the lowest SRV setpoint (1103 psig).

Reactor Vessel Head Spray

The vessel head spray line is used during the shutdown cooling mode of operation to cool the upper vessel area prior to flood-up of the vessel. If the isolation check valves and the motor operated isolation valves fail, the low pressure RHR system LPCI line will be over pressurized.

The result is identical to paragraph 4.7.2.1 mentioned above. Therefore, the same indications will be available to the operators.

Low Pressure Core Spray Injection Line

Failure of the LPCS testable check valve and/or the normally closed injection valve would over pressurize the LPCS piping and possibly causes a rupture. The relief valve lifts automatically at a set pressure of 586 psig and has the same design requirements as the RHR injection line relief valve.

High Pressure Core Spray Suction

The HPCS system starts automatically on level 2 or high drywell pressure. Upon actuation, the normally open suction valve from the condensate storage tank is signaled to open, the test return valves are signaled to close, and the normally closed injection valve is signaled to open. Subsequently, the injection valve receives an automatic close signal when vessel level reaches level 8 thus the pump will continue running with flow through the minimum flow line. If the minimum flow valve fails closed and the water leg pump discharge stop check valve fails open, there is a chance of over pressurizing the low pressure suction piping.

Operating Experiences

With two series check valves the probability of at least one of the check valves being seated and not leaking would be extremely high. In addition, if leakage were to occur to the point of causing a LOCA in the low pressure piping, the high differential pressure across the valve should cause the valves to seat, which would terminate the accident. However, actual operating experiences indicates that both check valves have failed to properly close.

The Nuclear Power Experiences Manual reports that between 1974 and 1978 there were nine dilution events in the cold leg accumulators of PWR plants. The following sections discuss other events that pertain to BWRs and interfacing system LOCAs.

Cooper Nuclear Station

The HPCI testable check valve failed to remain fully closed due to a broken sample probe wedged under the edge of the valve disc. The origin of the sample probe was traced to the feedwater system. The failure was not recognized until backflow of feedwater to the HPCI pump suction occurred.

LaSalle event on October 5, 1982

A testable check valve was tested with the plant at 20% power. The test was accomplished by opening the check valve bypass valve to equalize pressure across the check valve disc and then opening the check valve from the control room. Following the test, both the bypass valve and the testable check valve failed to reclose.

Pilgrim event on February 12, 1986 and April 11, 1986

On February 12, both the testable check valve and the normally closed LPCI outboard injection valve leaked, resulting in frequent high pressure alarms. These alarms occurred repeatedly for approximately two weeks prior to this event. Operators simply vented the piping after each alarm. On this date, the outboard injection valve was manually closed and its closing torque switch replaced. The plant continued operation until April 11, at which time, more high pressure alarms occurred. It was discovered that the outboard injection valve started leaking again and subsequently required a plant shutdown to facilitate repairs.

Dresden Unit 2 Event

On February 21, 1989, with Dresden Unit 2 operating at power, temperature was greater than normal in the HPCI pump and turbine room. The abnormal heat load was caused by feedwater leaking through uninsulated HPCI piping to the condensate storage tank. During power operation, feedwater temperature is less than 350°F, and feedwater pressure is approximately 1025 psi. Normally, leakage to the condensate storage tank is prevented by the injection check valve, the injection valve, or the discharge valve on the auxiliary cooling water pump.

On October 23, 1989, with the reactor at power, leakage had increased sufficiently to raise the temperature between the injection valve and the HPCI pump discharge valve to 275°F and at the discharge of the HPCI pump to 246°F. Pressure in the HPCI piping was 47 psia. On the basis of the temperature gradient and the pressure in the piping, the licensee concluded that feedwater leaking through the injection valve was flashing and displacing some of the water in the piping with steam. This conclusion was confirmed by closing the pump discharge valve (M034) and monitoring the temperature of the piping. As expected, the pipe temperature decreased to ambient.

The event at Dresden is significant because the potential existed for water hammer or thermal stratification to cause failure of the HPCI piping and for steam binding to cause failure of the HPCI pump. Further, failure of HPCI piping downstream from the injection valves would cause loss of one of two feedwater pipes.

The licensee had not heard the noise that is usually associated with water hammers. Never the less, loosening of pipe supports, damage to concrete surfaces, and the pressure of steam in the piping strongly indicated that water hammers had occurred in the HPCI system, probably during HPCI pump tests or valve manipulations.

PRA Insight

NUREG/CR-5928, ISLOCA Research Program, primary purpose is to assess the ISLOCA *risk* for BWR and PWR plants. Previous reports (NUREG/CR-5604, 5745, and 5744) have documented the results of ISLOCA evaluations of three PWRs and to complete the picture a BWR plant was examined. One objective of the Research Program is identification of generic insights. Toward this end a BWR plant was chosen that would be representative of a large percentage of BWRs.

The reference BWR plant used as the subject of ISLOCA analysis was a BWR/4 with a Mark-I containment. Power rating for the plant is 3293 MWt. BWRs of similar design include:

- Brown's Ferry 1,2, & 3
- Peach Bottom 2 & 3
- Enrico Fermi
- Hope Creek
- Susquehanna 1 & 2
- Limeric 1 & 2

NUREG/CR-5928 document describes an evaluation performed on the reference BWR from the perspective of estimating or bounding the potential *risk* associated with ISLOCAs. A value of 1×10^{-8} per year was used as the cutoff for further consideration of ISLOCA sequences.

A survey of all containment penetrations was performed to identify possible situations in which as ISLOCA could occur. The approach taken began with an inventory of these penetrations to compile a list of interfacing systems. Once the list was complete, the design information for each system was reviewed to determine the potential for a rupture given that an over pressure had occurred. The systems included:

- reactor core isolation cooling system
- high pressure coolant injection system
- core spray system
- residual heat removal system
- reactor water cleanup system
- control rod drive system

4.8 Service Water System Problems

References:
- NRC Bulletin 81-03
- NRC Generic Issue-51
- NUREG 1275, Vol.3
- NRC Generic Letter 89-13
- 10 CFR 50 General Design

Learning Objectives :

1. State three safety related functions performed by most service water systems.

2. List the most frequently observed cause of system degradation, other than system fouling.

3. List three fouling mechanisms that can lead to system degradation

4.8.1 Introduction

Because the characteristics of the service water system may be unique to each facility, the service water system is defined as the system or systems that transfer heat from the safety-related structures, systems, or components to the ultimate heat sink (UHS). Attached are selected service water systems of operating plants, to illustrate some of the differences found in the industry.

The service water system provides cooling water to selected safety equipment during a loss of offsite power. Failure of the service water system would quickly fail operating diesel generators and potentially fail the low pressure emergency core cooling pumps due to the loss of cooling pump or room coolers.

Objective #1
- Low pressure ECCS pumps and room coolers
- HPCI &RCIS room coolers
- EDGs
- RHR heat exchangers
- RBCCW

In addition the High Pressure Coolant Injection and Reactor Core Isolation Cooling pumps would fail upon loss of their room cooling.

There is an outstanding issue regarding the need for service water that involves the issue of the core spray and residual heat removal pumps requiring service water cooling. One utility (PECo) has stated that these pumps are designed to operate with working fluid temperatures approaching 160°F without pump cooling. However, because it is uncertain whether the suppression pool water temperature can be maintained below 160°F in some core damage PRA sequences the analyses still assume failure of the low pressure emergency core cooling pumps.

The NRC staff has been studying the problems associated with service water cooling systems for a number of years. At Arkansas Nuclear Plant, Unit 2, on September 3, 1980, the licensee shut down the plant when the resident inspector discovered that the service water flow rate through the containment cooling units did not meet the technical specification requirement. The licensee determined the cause to be extensive flow blockage by Asiatic clams (Corbicula species, a non-native fresh water bivalve mollusk). Prompted by this event and after determining that it represented a generic problem of safety significance, the NRC issued Bulletin No. 81-03, "Flow Blockage of Cooling Water to Safety System Components by Asiatic Clam."

After issuance of Bulletin No. 81-03, one event at San Onofre Unit 1 and two events at the Brunswick station indicated that conditions not explicitly discussed in the bulletin can occur and cause loss of heat transfer to the UHS. These conditions include:

- Flow blockage by debris from shellfish other than Asiatic clams and mussel.
- Flow blockage in heat exchanger causing high pressure drops that can deform baffles and allow flow to bypass heat exchanger tubes.
- A change in operating conditions, such as a change from power operation to a lengthy outage, that permits a buildup of biofouling organisms.

By March 1982, several reports of serious fouling events caused by mud, silt, corrosion products, or aquatic bivalve organisms in open-cycle service water systems had been received. These events led to plant shutdowns, reduced power operation for repairs and modifications, and degraded modes of operation. This situation forced the NRC to establish Generic Issue 51, :Improving the Reliability of Open-cycle Service Water Systems." To resolve this issue, the NRC initiated a research program to compare alternative surveillance and control programs to minimize the effects of fouling and increase plant safety.

4.8.2 AEOD Case Study

The Office for Analysis and Evaluation of Operational Data (AEOD) initiated a systematic and comprehensive review and evaluation of service water system failures and degradation at light water reactors from 1980 to early 1987. The results of that AEOD case study was published in "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3.

Objective #3
- **Corrosion and erosion**
- **Biofouling**
- **Foreign material and debris intrusion**

Of 980 operational events involving the service water system reported during this period, 276 were deemed to have potential generic safety significance. Of the 276 events with safety significance 58 percent involved system fouling. The fouling mechanisms included corrosion and erosion (27%), biofouling (10%), foreign material and debris intrusion (10%), sediment

Objective #2

most frequently observed cause of service water system degradations and failures is **personnel and procedural errors** next to system fouling.

deposition (9%), and pipe coating failure and calcium carbonate deposition (1%).

The **second most frequently** observed cause of service water system degradations and failures is **personnel and procedural errors** (17%), followed by seismic deficiencies (10%), single failures and other design deficiencies (6%), flooding and significant failures 4% each.

During the evaluation period 12 events involved a complete loss of the service water system.

Following the evaluation of service water events, several NRC requirements were originated:

- Conduct, on a regular basis, performance testing of all heat exchangers, which are cooled by the service water system and are needed to perform a safety function. The testing performed should verify heat exchanger heat transfer capability.
- Require licensees to verify that their service water systems are not vulnerable to a single failure of an active component.
- Inspect, on a regular basis, important portions of the service water piping for corrosion, erosion, and biofouling.
- Reduce human errors in the operation, repair, and maintenance of the service water system.

4.8.3 Summary

Due to the significance of the service water system's contribution to core damage frequency in the probability risk assessment studies and the systems' troubled operating experiences, the NRC determined that compliance with 10CFR50 Appendix A, General design Criteria (GDC) is in question. Table 4.8-1 lists the service water system's contribution to core damage frequency (CDF) in terms of an absolute value and a percentage for a collection of BWRs and PWRs. The contribution made by service water to the total CDF varies from <1% to 65%. The reasons for the large differences for the most part have to do with the degree of dependency a plant has on service water, the reliability of the systems themselves, and to some extent, the differences in the PRAs in terms of modeling assumptions

$\frac{\text{CDF contribution}}{\text{Mean CDF}} = \%\ \text{contribution}$

$\frac{1.9 \times 10^{-4}}{2.9 \times 10^{-4}} \simeq 65\%$

Generic Letter 89-13 was issued to require licensees to supply information about their respective service water systems to assure the NRC of such compliance and to confirm that the safety functions of their systems are being met.

Figure 4.8-1

Cooper Station:

Suction from river (UHS)
SW supplies D/Gs, REC HTXs, and RHR HTXs
Discharge to river
REC is the same as reactor building closed cooling water systems

Figure 4.8-2

Fitzpatrick

Suction from UHS

Figure 4.8-3

WNP-2
Suction from Cooling towers
SW supplies Dgs, ECCS or safety related pumps, motors and room coolers
Discharges to cooling towers and spray pond

Figure 4.8-4

LaSalle

Suction from Cooling towers
SW supplies Dgs, ECCS or safety related pumps, motors and room coolers
Discharges to cooling lake

Viewgraph of Learning Objectives

4.9 Stress Corrosion Cracking

Learning Objectives

1. List five reactor vessel internal components that are susceptible to IGSCC/IASCC.
2. List the purposes of the core shroud.
3. List the five factors used to establish a susceptibility ranking to shroud cracking.
4. List the three accident scenarios of primary concern associated with weld cracks in core shrouds.
5. List the three primary fixes being used to mitigate IGSCC/IASCC concerns.
6. List the two benefits of zinc injection.
7. List the two inspection methods currently being employed to locate cracks.

Introduction

4.9.1 Introduction

Ask the class for a definition of corrosion.

Corrosion is the weakening of a structural component as a result of a material deterioration caused by electrochemical reaction with the surrounding medium. The effects can be global or highly localized. Global effects are referred to as general corrosion. The localized effects usually involve some form of crack development.

Global/general corrosion (ferric oxide, Fe_2O_3)

Stress corrosion cracking (SCC)

Stress corrosion cracking (SCC) is a common form of highly localized corrosion phenomena. SCC can occur in ductile materials with little or no plastic strain accumulation associated with the process. The development of SCC in a structural component requires the simultaneous presence of three conditions:

Show viewgraph of the VENN diagram for the three factors necessary for SCC.

- **a conducive environment**
- **a susceptible material**
- **tensile stress above the threshold level**

SCC is not expected to develop when any one of the three conditions is absent from the operating environment. Thus the **elimination of one condition is the basis for formulating strategies to control SCC.** Depending on the alloy compositions and the nature or stressors present, cracks can develop along grain boundaries. When this occurs it is called inter granular stress corrosion cracking (IGSSC).

corrosive environment

The hot oxygenated water creates a corrosive environment in the BWR pressure vessel. The dissolved oxygen increases the electrochemical potential of type 304 stainless steel and makes them vulnerable to corrosion attacks. **The presence of impurities, such as chlorides and sulfates, in the reactor coolant system may accelerate the crack development process.**

Susceptible Material

Non-magnetic====>>>
Tensile stress above the threshold level

In addition to the oxygenated water, the welding process can provide the other two conditions necessary for the development of SCC. **When a weld is cooled down through the temperature range from 1500 to 900 °F (820 to 480 °C) type 304 stainless steel undergoes a sensitization** process characterized by chromium depletion at grain boundaries. The sensitization makes **austenitic stainless steels** susceptible to corrosion attacks. **The presence of residual stresses in weld heat affected zones supplies the third requirement for SCC.** Most of the SCC failures in BWR internals are found in weld heat affected zones.

Susceptibility ranking for each plant Objective #3

Because BWR vessel components are made of material that are susceptible to IGSCC, the industry has attempted to establish a **susceptibility ranking for each plant** which considers:

- length of operation
- water chemistry/conductivity
  material susceptibility
- fabrication
- fluence

Shorter operational times, low conductivity reactor coolant water, the use of low carbon materials, minimal surface cold work, low weld residual stresses, and lower fluence levels reduce the likelihood of cracking.

Inspection Methods

Objective #7

4.9.2 Inspection Methods

At the present there are two methods being employed to locate cracks and to estimate their lengths. **The two methods are the specialized visual inspection (VI) and ultrasonic testing (UT).** Specialized visual inspections have primarily been performed on the outside diameter (OD) weld surfaces of the shroud. Inside diameter (ID) surfaces have also been performed, although the presence of other reactor vessel internal components have limited the inspectable area or prohibited visual inspections altogether.

Ultrasonic testing examinations in some locations provide the only possible means of examination since the visual inspection accessibility of this region is blocked. One such area is the H2 (Figure 4.9-2) weld location that is blocked by the core spray piping and spargers

Color viewgraph of vessel

Have the class provide a list of penetrations/components that could experience SCC

4.9.3 Field Experiences

AS you cover the penetrations and components, use the Astound slide presentation package located in the 504 lesson plan folder for this chapter.

Cases of IGSSC and Irradiation Assisted Stress Corrosion Cracking (IASCC) have been reported at various BWRs. The cases range form penetrations to structural components. This section will discuss the various reactor vessel components and penetrations that are susceptible to stress corrosion cracking.

4.9.3.1 CRD Stub Tube Penetration

Objective #1

A few cases of IGSSC have been reported in the CRD stub tube penetration in the BWR fleet. In all cases, indications were found in furnace sensitized 304 stainless steel material. There is no history of CRD stube tube stress corrosion cracking in Alloy 600 or Allow 182 J-welds.

The CRD stub tube penetrations are Alloy 600 and are welded inside the vessel to a 304 stainless steel CRD housing by an Alloy 182 field weld (known as a J-weld). The penetration is also welded with Alloy 182 to the inside of the bottom head.

SCC is a potentially significant degradation mechanism for Alloy 182 and sensitized 304 stainless steel. Weld stress is the only significant stress for this penetration.

If the sensitized regions or the weld between the penetration and housing developed SCC, there should be no operational impact since reactor water exists on both sides of the housing. In an extreme case where the housing could be considered deformed, the ability of the housing to support the fuel and the ability of the control blade to insert could be questionable. SCC in the J-weld could also lead to leakage between the CRD housing and stub tube. There is a possibility of leakage in the large number of stub tubes, so these tubes would in turn require inspection and/or repair.

Recommended fix

Objective #1

If repair is necessary due to CRD stub tube inspection, the General Electric recommended fix is to install a mechanical sleeve.

4.9.3.2 In-Core Housing

An instance of IGSCC occurred in an in-core housing at a plant located outside the United States. The plant is similar in design to a BWR/4. Reactor pressure vessel leakage was discovered at the joint where the in-core housing penetrates the bottom head. Leakage was found to be caused by a SCC thru-wall crack in the heat affected zone.

If the sensitized region above the weld developed IGSCC, leakage would occur inside the penetration. If the penetration-to-vessel Alloy 182 weld developed SCC, the crack would grow through the housing or along the weld and cause a leak. In a worst case scenario, the crack may grow into the vessel, where service-induced crack growth might cause the crack to reach a critical size where lower temperature operation such as pressure testing could initiate brittle fracture of the reactor vessel. Margins in operating methods make this scenario unlikely, but the consequences would be severe from both a safety and economic view.

Recommended fix

Objective #1

If repair is necessary for the in-core housing, GE-NE would expand the housing to make contact with the vessel bottom head material.

4.9.3.3 Recirculation Inlet and Outlet Nozzle

Safe end - - The end of the nozzle that attaches to the pipe.

IGSCC has been found in recirculation inlet nozzles. The initiation of IGSCC occurs in the Alloy 182 weld butter which joins the safe ends to the nozzle attachment. A few instances have found some extensions of cracking into the stainless steel safe end nozzle material. SCC has also been observed in the 304 stainless steel thermal sleeve of a domestic BWR/3. No cracking has been observed propagating in the low alloy steel.

Objective #1

In a worst case scenario, the crack may grow into the vessel, where service-induced crack growth might cause the crack to reach a critical size where lower temperature operation such as pressure testing could initiate brittle fracture. Margins in operating methods make this scenario unlikely, but the consequences would be severe from both a safety and economic view.

4.9.3.4 Shroud-to-Shroud Support Weld

The shroud support consists of a horizontal Inconel plate (in four weld segments) welded on the inside of the vessel. A vertical Inconel ring is welded to the support plate which is in turn welded to the shroud. Structural support is added to the support plate by 22 Inconel gusset plates welded to horizontal plate and to the vessel wall.

No field data dealing with IGSCC failures in shroud-to-vessel welds is available; due to the difficulty in accessing this area. Many plants have not completed visual examinations of this area.

If SCC initiation occurred, service-induced crack growth may cause cracks to grow into the vessel's low allow steel. Once in the allow steel, cracks could reach critical size so that the lower temperature operations like pressure testing could initiate brittle fracture. Margins in operating methods make this scenario very

Objective #1& 2

unlikely, but the consequences would be severe from both a safety and economic point of view.

4.9.3.5 Core Shroud

Have the class give the purposes of the core shroud and then place a viewgraph on the board.

The core shroud is a stainless steel cylinder assembly, Figure 4.9-1, that surrounds the core. The shroud provides the following functions/purposes:

- **A barrier to separate or divide the upward core flow from the downward annulus flow.**
- **A vertical and lateral support for the core plate, top guide and shroud head.**
- **A floodable volume in the event of a loss of coolant accident.**
- **A mounting surface for the core spray spargers.**
- **A core discharge plenum, directing the steam water mixture into the moisture separator assembly.**

304L signifies a low carbon content type 304 stainless steel.

The core shroud is welded to and supported by the baffle plate (shroud support plate). The upper surface is machined to provide a tight fit with the mating surface of the shroud head. Mounted inside the upper portion of the shroud, in the space between the top guide and the shroud head base, are the two core spray spargers. Typical cross-sectional dimensions range from 14 feet to more than 17 feet in diameter with a wall thickness between 1.5 inches to 2 inches. Core shrouds were fabricated from 1.5 inches to 2 inches primarily for stiffness considerations for transport and installation. Boiling Water Reactor (BWR) shrouds are typically manufactured from either plates or plates and ring forging of type 304 or 304L stainless steel. Fabrication of the plate portions of the shroud involves both axial and circumferential welds. Fabrication of the ring forging involves only circumferential welds. The circumferential welds in the shroud are identified according to their vertical location as shown in Figure 4.9-1, although the exact numerical notation may vary from plant to plant.

Numerous instances of shroud

cracking have occurred in the BWR fleet. The first occurrence of cracking occurred in a BWR/4 located outside the United States. Cracking indications were observed in the circumferential beltline seam weld of the Type 304 stainless steel (with medium carbon content) core shroud. Circumferential crack indications with short axial components were observed in three locations on the inside surface of the shroud and were confined to the heat affected zone of the circumferential weld. Short, axial indications were also observed on the outside surface of the shroud in the same heat affected zone. Multiple UT examinations have been performed after these indications were found, with the most recent exam finding significant crack growth over a single cycle. An evaluation of cracking was performed and found that the cracking was due to IASCC.

The second instance involved cracking at a domestic GE BWR/4. Crack indications were discovered during in-vessel inspection of reactor internals. Indications of cracking were circumferentially located in the top guide support ring parallel to the plane of the ring and adjacent to the H-3 weld. Indications were also found on the outside surface of the shroud adjacent to the H-4 weld, oriented axially and measuring about on inch. Crack initiation was found to occur by IGSCC and was accelerated by IASCC contribution.

The third instance of cracking occurred in another domestic BWR/4. Indications were seen in both circumferential and axial directions at the H-3 and H-4 welds. In addition, circumferential indications were observed in the shroud plate associated with the vertical weld.

In order to assess the significance of potential cracking worse than that observed to date, the NRC has evaluated the safety implications of a postulated 360 degree circumferential separation of the shroud. The staff's evaluation determined that the detectability and consequences of 360 degree through-wall cracking are directly related to weld location at which the cracking occurs. In addition, the staff's evaluation identified three accident scenarios:

Objective #4

- **main steam line break**
- **recirculation line break**
- **seismic events**

At the upper shroud elevations (H1, H2, and H3), lifting of a separated shroud is expected to occur due to differential pressure in the core being sufficient to overcome the downward force created by the weight of only a small portion of the remaining upper shroud assembly. As such, bypass flow through the gap created by the separation is sufficient to cause a power/flow mismatch indication in the control room. The main concern associated with cracks in the upper shroud region is during a steam line break. With a main steam line failure, the lifting forces generated may elevate the top guide sufficiently to reduce the lateral support of the fuel assemblies and could prevent control rod insertion.

At the lower shroud elevations (H4, H5, ...), shroud lifting may not occur due to insufficient core pressure differential necessary to overcome the downward force from the weight of the shroud. As such, detectible bypass flow is not assured. The main concern associated with cracks in the lower elevations of the core shroud is the postulated recirculation line break. Recirculation line break loadings, if large enough, could cause a lateral displacement or tipping of the shroud which could affect the ability to insert control rod and may result in the opening of a crack. If the leakage were large enough, it could potentially affect the ability to reflood the core and maintain adequate core cooling flooding. In addition, the ability to shut down the reactor with the Standby Liquid Control System could be reduced.

Other concerns have been raised over the potential for damage to reactor vessel internals due to shroud displacement during postulated accident conditions. In particular, the possibility may exist for damage to the shroud support legs due to impact loading from the settling of the shroud after a vertical displacement. In addition, displacement of the shroud could cause damage to core spray lines.

Objective #1

The NRC developed a probabilistic safety assessment regarding shroud separation at the lower elevation for two plants, Dresden Unit 3 and Quad Cities Unit 1. The staff made conservative estimates of the risk contribution from the shroud cracking and concluded that it does not pose a high degree of risk at this time. However, the staff considers a 360 degree cracking of the shroud to be a safety concern for the long term based on:

- Potentially exceeding the ASME Code structure margins if the cracks are sufficiently deep and continue to propagate through the subsequent operating cycle.
- The uncertainties associated with the behavior of a 360 degree through-wall core shroud crack under accident conditions.
- The elimination of a layer of defense-in-depth for plant safety.

4.9.3.6 Access Hole Cover

The access cover is a 2 inch thick Alloy 600 cover welded to the 2 ½ inch thick shroud support. Extensive cracking has been found in several access hole covers in the BWR fleet. Cracking has occurred in creviced Alloy 600 covers welded with Alloy 182 weld metal and has initiated in the heat affected zone of the cover plate. Intermittent circumferential cracking has been the most common orientation of cracking.

In the worst case, access hole cover cracking could progress through wall and cause the cover to detach either partially or completely. A substantial flow path from the bottom head into the annulus region would be created, impacting core flow distribution during normal operation. The distribution would be detectable at significant levels. Such cracking would impact the boundary which assures 2/3 core coverage following a LOCA event. The consequence of cracking is high.

General Electric has replaced approximately 20 access hole covers to date. With a cost of approximately $6 million per plant.

Objective #1

4.9.3.7 Jet Pump Riser Brace

The jet pump riser brace is connected to the riser pipe by a single bevel weld. At least one occurrence of IGSCC has been documented by General Electric. During visual examination at a BWR/4, a crack was found on the weld that attaches the riser brace yoke to the jet pump riser pipe. Cracking extended out of the heat affected zone of the weld and into the riser pipe. Although no definitive answer was reached, it is believed that the cracking initiated by an IGSCC mechanism and propagated by high cycle fatigue.

At the crack location between the brace and the riser, a crack could have significant consequence on operation and safety. The brace is intended to provide structural support at the upper part of the jet pump assembly and lateral support to maintain jet pump alignment.

4.9.4 Activities

BWR executives formed the BWR Vessel and Internals Project (BWRVIP) in June of 1994. One of the BWRVIP's first challenges was to address integrity issues arising from service-related degradation of key components, beginning with core shroud cracking. BWRVIP also implemented a proactive program to develop products and solutions that bear on inspection, assessment, mitigation, and repair.

Through BWRVIP, utilities are developing, sharing, and implementing cost-effective strategies and products for resolving vessel and internals integrity and operability problems. BWRVIP also provides the regulatory interface on generic BWR vessel and internals matters. During the first year of BWRVIP activities, the following products were developed for the core shroud: Inspection and Flaw Guidelines, NDE Uncertainty and Procedure Standard, and Repair Design Criteria.

Objective #5

4.9.4.1 Hatch Fix

The design of the Hatch Unit 1 core shroud modification consists of four stabilizer assemblies, which are installed 90 degrees apart. Each stabilizer assembly consists of a upper bracket, tie rod, upper spring, lower spring, lower bracket, intermediate support, and other minor components. The tie rods serve to provide an alternative vertical load path from the upper section to the tie rod assembly through the shroud support plate gusset attachments. These tie rod assemblies maintain the alignment of the core shroud to the reactor vessel. At the top guide elevation, the upper springs are designed to provide a radial load path from the shroud to the RPV. The lower springs are designed to provide a similar radial load path (from the shroud to RPV) at the core support plate elevation. The upper bracket is designed to provide attachment to the top of the shroud, and to restrain the upper shroud weld (weld H1). The middle support for the tie rods is designed to limit the radial movement of the tie rods. Wedges placed between the core shroud plate and the shroud prevent relative motion of the core plate with the shroud.

The stabilizer assemblies are designed to prevent unacceptable lateral or vertical motion of the shroud shell sections, assuming failure (360 degrees through wall) of one or more of the structural circumferential shroud welds. The functions of the components are as follows:

- upper brackets are designed to restrain lateral movement of the shell between welds H1 and H2, and the shell between welds H3 and H4

- the limit stops located at the middle of the tie rods are designed to restrain lateral movement of the shell between welds H4 and H5

- the lower springs contact the shroud, and are designed to restrain the shell segments between welds H5 and H6a, H6a and H6b, and welds H6b and H7

Objective #5

- the gussets, which were originally included as part of the shroud support design, are designed to preclude unacceptable motion of the shroud between welds H7 and H8

Materials for the stabilizer assemblies was selected to provide protection for the life of the plant. In addition, the material has a different coefficient of expansion than the core shroud and causes a compressive load when at normal temperature and pressure.

4.9.4.2 Protection Against IGSCC

Protection against IGSCC deals mainly with some form of primary water chemistry control process.
Hot oxygenated water creates a corrosive environment in the BWR pressure vessel. Dissolved oxygen in water increases the electrochemical potential of type 304 stainless steel and makes them vulnerable to corrosion attacks. By controlling the environment surrounding the reactor vessel internals, IGSCC can be mitigated.

Hydrogen Addition

The purpose of hydrogen water chemistry control is to suppress oxygen in the reactor water. By suppression the oxygen level in reactor water:

- General corrosion is controlled
- Characteristics of corrosion film layer in recirculation piping and reactor vessels are changed
- A reduction in the oxidation state of chromium is realized.

In response to the unacceptable degradation of reactor vessel components from Intergranular Stress Corrosion Cracking (IGSCC) a number of BWRs have adopted hydrogen water chemistry. Hydrogen water chemistry implies a low dissolved oxygen content coupled with low conductivity.

Hydrogen water chemistry appears to improve the margin for stress corrosion and corrosion fatigue of carbon and low alloy steels, but has a slight adverse affect on their overall corrosion kinetics.

Under hydrogen water chemistry, the dissolved oxygen in the recirculation systems decreases below the acceptable value for minimal corrosion of carbon steel piping. At very low levels of dissolved oxygen the protective corrosion film on carbon steel undergoes dissolution and produces accelerated corrosion of the base metal. Therefore, sufficient oxygen is added to the condensate system to maintain oxygen between 20 and 50 ppb.

Hydrogen water chemistry provides a reducing environment that not only lowers the oxidation potential of reactor water, but also favors formation of Spinel. Spinel is a thinner, more adherent film, of a complex metal matrix consisting of iron, chromium, nickel, cobalt, manganese, copper and zinc.

Historically, the corrosion films on BWR components are a combination of hematite and spinel oxides. Higher fractions of hematite in the corrosion film lead to thicker and less protective oxides. This type of corrosion film tends to increase radiation buildup by permitting more corrosion products to enter solution. This tendency is counter balanced because hematite does not have a natural site for crystal formation by divalent ions, such as cobalt. Hematite has a lower cobalt concentration than corrosion films dominated by spinel structure. This means that the radioactive material buildup is not controlled solely by oxide layer thickness.

BWR chemistry without hydrogen water control provides oxidizing conditions in the reactor coolant. Under oxidizing conditions, stable oxygen-16 is activated to nitrogen-16 by a neutron-proton reaction. The resulting nitrogen-16 is primarily in the form of soluble nitrates (NO_3) and nitrites (NO_2) with a small amount in the form of volatile ammonia (NH_4).

Hydrogen water chemistry changes the BWR coolant to a reducing environment. Under reducing conditions, the chemical equilibrium shifts from nitrate/nitrite in favor of volatile ammonia. Nitrogen-16 carryover into the main steam system then increases by as much as a factor of five at full power. The carryover of nitrogen-16 results in significant increased dose rates in the turbine building during plant operation from 6.1 and 7.1 Mev gamma photons produced during radioactive decay. During outages, the dose rate from nitrogen-16 is not a factor since it is no longer being produced and it has a very short half-life of only 7.1 seconds.

Objective #5 & 6

Zinc Injection

The presence of **zinc in the reactor coolant increase the spinel fraction in oxide formations on stainless steels.** Spinel is a thinner (by a factor of six or more) more protective film oxide than hematite (Fe_2O_3). The corrosion protection provided by spinel based film is greater than that formed by divalent cations commonly found in BWRs. Zinc competes with cobalt for available crystal lattice sites in the spinel and under hydrogen water chemistry is the dominate divalent ion in the crystal matrix of spinel; thereby, allowing little cobalt-60 buildup. It is hypothesized that the excess of zinc ions in a mixed metal oxide migrate to the vacant defect sites and block ion migration by other ions. This produces a quasi-stoichiometric oxide that is highly protective to the base metal.

Reducing the soluble cobalt-58 and cobalt-60 in the in the reactor coolant is an additional benefit. **By reducing the long lived radioactive material that contribute to personnel exposure, BWRs see a positive impact in ALARA space.**

Objective #5

4.9.4.3 Noble Metals Injection

Noble metals injection has proven that it works through the injection of platinum group noble metals into the reactor water, depositing a single-atom thickness of platinum and rhodium on wetted internal surfaces. This catalytic layer provides the desired electrochemical corrosion potential levels for many components at a very low hydrogen injection level and extends hydrogen water control benefits to additional vessel internals with minimal increases in operation dose rates. With the use of noble metals injection, approximately one-fifth of the hydrogen injection values used in traditional hydrogen injection are needed.